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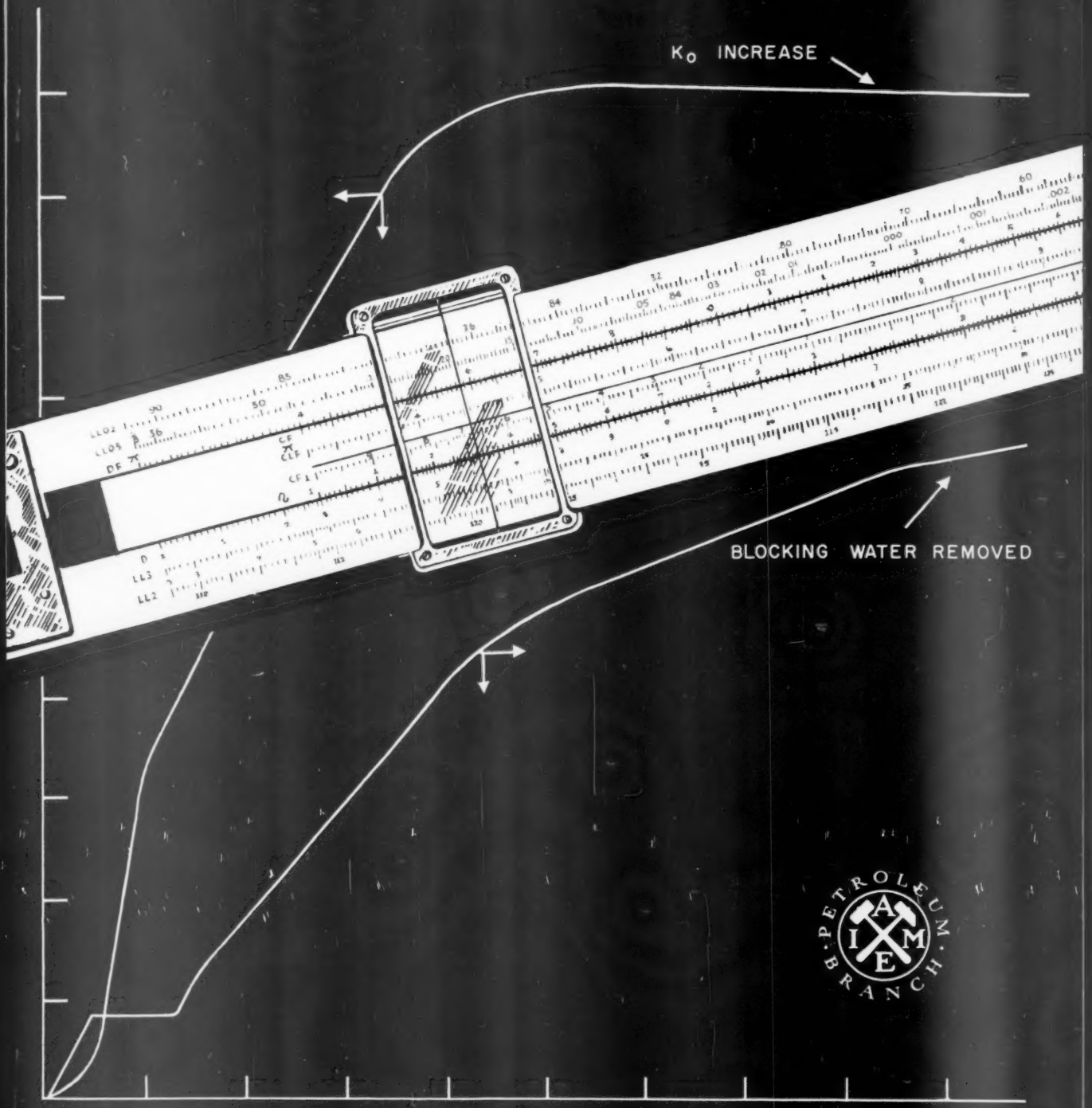

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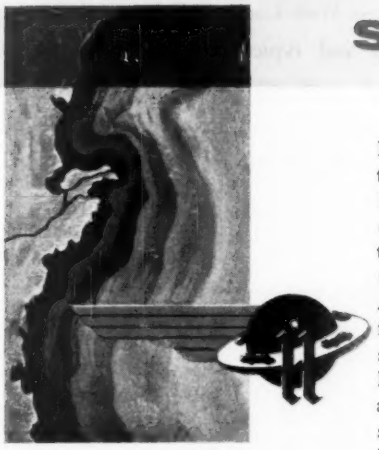

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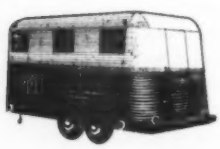

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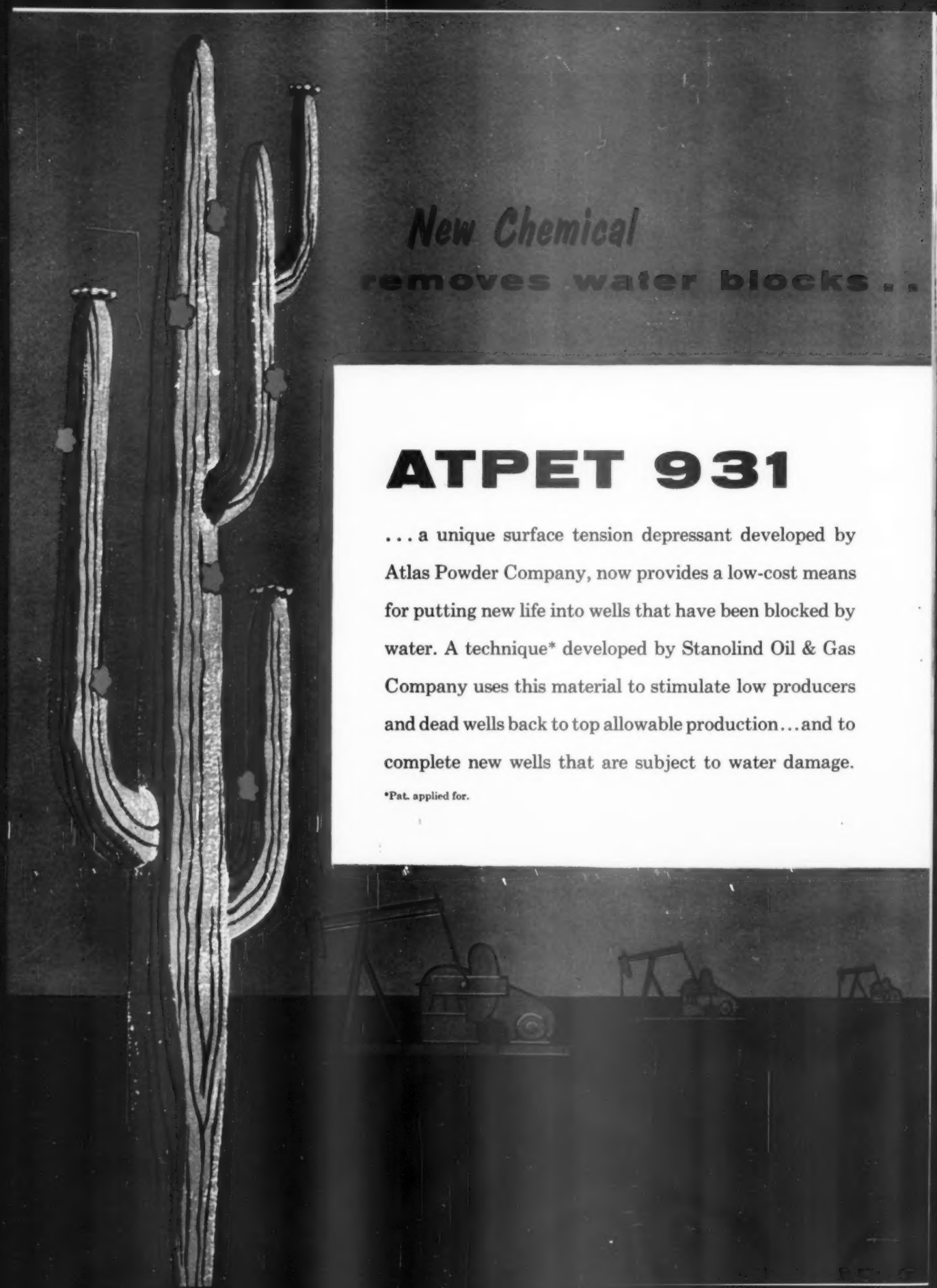

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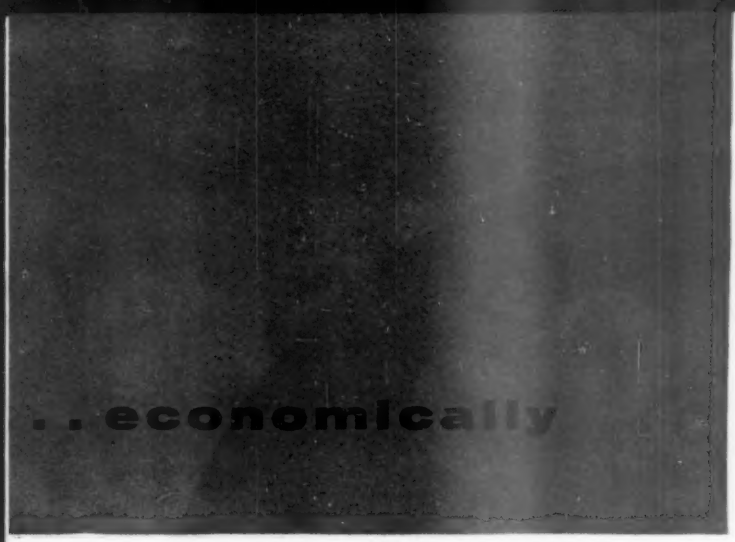

Here are a few examples of what ATPET 931 is doing:

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EDITORIAL

KNOW YOUR TOOLS!

ERNEST K. PARKS
MEMBER AIME

PETROLEUM PRODUCTION ENGINEER
LOS ANGELES, CALIF.

As we search more intensively for favorable indications of oil and gas accumulations, as we drill deeper into the earth, as we develop the discoveries which result from brains, machines and luck, as we contribute our bit to the profitable extraction of hydrocarbon reserves, and to handling of the products, let us reflect upon the tools which enable us to stay in business.

An engineer is one who is skilled in the art of obtaining beneficial use of laws and resources of nature. Whether his work is in research, design, supervision, or administration, he must conceive ideas. He must then make them useful by devising methods for their execution. Herein lies the range between primitive practice and expert efficiency. Modern tools make the difference, for a tool includes "anything which serves as a means to an end." Thus a tool may be a device or a service, and it follows that the more familiar the engineer is with tools, the greater will be his capacity — and his achievements.

Study Available Tools

The engineer with ideas but no tools is regarded as a dreamer. When he finds the tool, he becomes a genius. But ones does not have to be a genius to be a success. Tools, that is, devices and services, are so plentiful that now an engineer who studies the tools available today can attain outstanding success by merely using them to advantage. The opposite is also true. He who is ignorant of the facilities about him will soon succumb in the dust of those who speed along the road of progress.

A very little experience should convince anyone that the development of a new tool, an invention, if you please, is a precarious undertaking, full of frustration, heartaches, financial risk, and possible bankruptcy. We should, therefore, appreciate what has been done.

Tools Brought Changes

In oil, whether it be exploration, production, transportation or refining, there are still several hundred in AIME who can recall the days when the plane table was the leading tool of the oil finder and 5,000 ft the limit of the drill, when a tank farm was essential every few miles along the pipeline, and when gasoline had to be found, not made. Ideas *and tools* have made the change.

The engineer of today has a heritage of tools. His education in fundamentals is a first requirement, but it is experience which makes him useful, and his usefulness is in direct proportion to his knowledge of tools. Today's treasure house of aids to engineering is so vast that specialization is necessary, but the specialist should beware of the old fashioned single track. Great rewards await those who combine an idea with tools already at hand. As examples, consider the adaptation of the known electrical oscillograph to oil finding, and also the use of the cyclotron in gas analysis of minute accumulations in top soil. The first application resulted in billions of barrels of oil reserves pointed out by geophysics, the other in the now standard mass spectrometer.

Sources of Knowledge

In reverse, it is easy to recollect how suppliers sought out problems which could be solved by their tools. The Schlumberger brothers received the Lucas Medal for their contribution to subsurface correlation. Others brought to petroleum engineering material, machines, and services which are accepted as routine by the younger generation, with no knowledge and perhaps with little appreciation of the lives and money expended in creation of these aids to engineers. It is not so long ago that drilling mud was not much more than sand, shale and water, there was only lap welded casing, cumbersome steam engines, fishtail bits, wooden derricks, no cement wagon, no perforating gun, no formation tester, no core barrel, no hydraulic brake, not even a sand shaker!

The moral to this story is that somewhere there are those who, through advertising, are trying to help you, or have what could be vital in the solution of your problem. These people are the suppliers of tools — devices and services. Suppliers are the life of your trade magazines and sponsors of your entertainment on the air. They support conventions through exhibits and contributions, and are making it possible to bring you the proceedings of your technical societies, including this journal. The advertising of the supplier is essential to your profession. Read it and prosper! ★★★

FEATURE ARTICLE

A LOW COST METHOD of PRODUCTION STIMULATION

A. W. GARST
MEMBER AIME

STANOLIND OIL AND GAS CO.
TULSA, OKLA.

Abstract

A simple treatment has been developed by which water-block is removed from oil wells by lowering oil-water interfacial tension to a very low value.

The treatment is made by injecting a crude oil solution of a carefully selected surface-active agent into the water-blocked formation. From 1,000 to 4,000 gals. of crude oil containing 1 per cent surface active agent is used. Shut-in time following treatment is usually from 12 to 24 hours.

The treatment has been used in 90 wells with successful results obtained in 39 wells representing seven formations in nine fields. The successful treatments have resulted in added productivity of 1,217 BOPD. Treatment cost is unusually low, compared with other types of well treatments and workovers normally done for improvement of productivity.

Introduction

The Problem

Although water-block removal has received considerable attention in the past, there has remained a need for an inexpensive, effective remedial treatment for water-blocked wells. This paper discusses the development of a remedial treatment utilizing a surface active agent which has shown considerable ability to increase production rates from wells in which some water-blocking was known or suspected to exist.

The need for a remedial treatment to remove water-block has been most clearly observed when established producing wells have shown marked productivity loss following exposure of the producing formations to water during workover operations involving water-base muds and cement. The need for such a treatment has not been so clearly evident in acidized wells. Partial water-block in such wells may occur undetected because of the complexity of operations and particularly when such wells are capable of making a maximum allowable after workover. Field tests reported in this paper show that the incidence of such water-blocking may be fairly high in at least one formation previously subjected to acidization.

Manuscript received in Petroleum Branch offices Aug. 2, 1954. Paper presented at Petroleum Branch Fall Meeting in San Antonio on Oct. 17-20, 1954.

[1]References given at end of paper.

Previous Work

Water-block removal is not a new subject. A complete history of water-block removal treatments could not be compiled at this time because of the absence of published information regarding the success or failure records of many treatments proposed in the past.

The amount of thought given to water-block removal is indicated by the numerous treatments covered by patents. By 1952 at least 28 patents had been issued covering such treatments. Some 200 materials, or classes of materials, were named or claimed in these patents. In general, the materials, or classes of materials, were claimed to remove water by reduction of oil-water interfacial tension, by reaction with the blocking water, by rendering the formation preferentially oil-wet, or by solution of the water in solvents such as acetone, alcohol, and the like. Practically all classes of possible surface active agents have been mentioned in these patents. Larsen[1] proposed the use of diglycol stearate, one of the materials now recognized as a non-ionic surface active agent.

Mechanism

Productivity loss following flooding of an oil producing formation with water has been generally described as caused by a water-block. This descriptive term does not define the physical mechanism involved in the blocking action. One specific mechanism has been explained by Muskat[2] who has shown that in preferentially oil-wet formations the presence of droplets of water would account for some productivity loss. Muskat showed that water droplets would be held up at constrictions in the capillary paths and would resist distortion to an extent determined by the droplet radius, the constriction radius, and the oil-water interfacial tension. The pressure drop required to effect distortion

and movement of a water droplet through an oil-wet constriction can be calculated according to the equation —

$$\Delta P = 2\gamma \, Cos \, \Theta \left(\frac{1}{r_1} - \frac{1}{r_2} \right) \quad . \quad . \quad . \quad (1)$$

where γ is the oil-water interfacial tension, r_1 is the radius of the constriction in the flow path, r_2 is the radius of the rear surface of the water droplet, and Θ is the contact angle between the water and the formation surface.

In one example, the above equation was applied to the case of a water droplet having a radius of 0.005 cm being forced through a constriction of 0.002 cm, and assuming an oil-water interfacial tension of 20 dynes/cm, the pressure required to effect movement of the water droplet would be 12,000 dynes/sq cm. If this pressure drop were to be provided by the parallel flow of the surrounding oil phase, and assuming the pore length to be 0.01 cm, the equivalent local pressure gradient required to effect movement of the water droplet would be approximately 36 atm or 530 psi/ft of formation. Pressure gradients of this magnitude would ordinarily not be available except immediately adjacent to the wellbore under most favorable conditions. By reducing the oil-water interfacial tension to 0.05 dynes/cm, the pressure gradient required could be reduced from 530 psi/ft to approximately 1 psi/ft.

While other water-blocking mechanisms involving interfacial forces can be visualized, the pressure gradient required to overcome the water-blocking action will vary as some direct function of the oil-water interfacial tension. With this fundamental consideration in mind, the nature of a process designed to effect water-block removal must necessarily include lowering the oil-water interfacial tension to a very low value.

Requirements

Treating Agent

In considering the requirements for a successful water-block removal treatment it was apparent that the surface active agent should possess the following characteristics:

A. It should be capable of reducing oil-water interfacial tension to a very low value.

B. The agent should not be adversely affected by high salt content of the water because the blocking water would, in some cases, be essentially formational water or spent acid.

C. It should not cause the formation to become oil-wet because of possible damage to water-wet formations to which the treatment might be applied.

D. The agent should be readily soluble to the extent required to obtain concentrations in the oil-water interface sufficient to permit water movement. A soluble agent should be preferred to one which might be only dispersible.

E. The tendency of the agent to be adsorbed on rock surfaces should be small to avoid loss of treating agent.

F. The agent should be safe to handle. In particular, the agent should not be poisonous nor cause irritation to the skin if the agent or solutions containing the agent were to be handled carelessly.

Process

In designing the experimental treatments, the following process requirements were set up:

A. The treatments should be made in the form of oil squeeze treatments in which crude oil would be used as the solvent for the surface active agent. Crude oil would be the most common available solvent as well as the least expensive.

B. The crude oil solution of agent should contain sufficient agent to obtain water-block removal. Experience has indicated that the optimum concentration of agent for general use lies within a relatively narrow range.

C. Treatments should be made with minimum injection pressure to avoid fracturing. Fracturing would be undesirable in experimental treatments to evaluate surface active effects, although in practice, combinations of this treatment with fracture treatments offer considerable promise.

Laboratory Work

Procedure

The first step in the development of the treatment consisted of comparing the oil-water interfacial tension effects of a number of surface active agents including some proprietary agents which had previously been used in oil-squeeze type treatments. A standard petroleum fraction consisting of aliphatic hydrocarbons containing 10 to 12 carbon atoms was used as the reference oil. The reference water was a neutral salt solution containing 9.6 per cent sodium chloride, 0.9 per cent calcium chloride, and 0.3 per cent magnesium chloride. This salt water corresponded to the formational water present in the virgin Springer sand cores which were available for the flow tests described below.

Oil-water interfacial tensions were determined for a number of concentrations of each surface active agent dissolved in the reference oil. Measurements were made with the DuNouy tensiometer. Measurements were made within five to eight minutes after the oil and water were placed in contact. This was done to speed up the collection of interfacial tension data. The data do not necessarily represent equilibrium interfacial tension values which might have been obtained after several hours contact.

The second step in the development work consisted of making flow tests in water-blocked test cores to compare the water-block removal properties of various selected surface active agents. Flow tests were made on cores taken with oil-base mud and brought to the laboratory while immersed in oil. Small test cores were cut from these cores using kerosene as a cutting fluid. The small test cores measured approximately ¾ in. in diameter by 1 in. in length. Each small test core was cleaned by mounting it in a simple liquid permeameter and flowing the reference oil until the effluent was colorless and the permeability to the reference oil was constant. Gas was removed prior to cleaning by saturating the test core with reference oil under a vacuum.

A partial water-block was created by flowing from 10 to 50 pore volumes of the reference water through each core and permitting the water to contact the core for a minimum of three days. The effective permeability to the reference oil was then determined and the flow

of reference oil continued until the effective permeability remained constant. Constant permeability was usually obtained after flowing 10 to several hundred pore volumes of reference oil through a core.

Water-block removal treatment was made by flowing 10 pore volumes of reference oil containing the desired concentration of surface active agent and the change in the effective permeability of the test core to the reference oil was observed. Saturation changes were observed by weighing the liquid saturated cores at appropriate stages of core preparation and treatment. All flow tests were made with a differential pressure of 14 to 15 psi.

Results

Typical interfacial tension data obtained during the investigation are shown in Table 1. Only a few of the compounds tested are shown. On the basis of the requirements for the agent, as previously outlined, Additive "H" appeared most promising for additional field and laboratory testing. Additive "H" is a non-ionic surface active agent described as a polyoxyethylated sorbitol derivative of cottonseed oil.

In Table 2 are shown the results of flow tests to compare the water-block removal obtained with Additive "H" and that obtained with each of two other proprietary agents which have been previously used in oil-squeeze type treatments.

In Table 3 are shown the results of additional tests to determine the effect of applying the treatment with Additive "H" to cores previously treated with other proprietary treating agents. These tests confirmed the greater effectiveness of Additive "H".

Typical water-block removal treatment results using virgin Springer sand cores from the East Velma field, Okla., are shown in Figs. 1 and 2. The Springer sand is a Pennsylvanian sand found in Southern Oklahoma. In collecting the data shown in each figure, a series of treatments were performed on a single test core and the concentration of Additive "H" was raised stepwise. At the time the greatest increase in effective permeability to oil (K_o) was obtained, the water freed by treatment was produced in the form of a fine emulsion of water-in-oil. This emulsion, however, broke out quickly to form a layer of free water in the downstream end of the flow cell. The close correlation between removal of blocking water and the recovery of effective permeability to oil (K_o) is pronounced.

The optimum concentration of surface active agent is not necessarily the same for all formations or for cores from the same formation. Fig. 3 shows the effect of varying concentrations of Additive "H" on effective permeability changes found in a partially water-blocked Curtis sand core from the Grass Creek field, Wyo. The Curtis sand is an Upper Jurassic sand found in parts of Colorado, Wyoming, and Utah. Maximum permeability recovery was obtained with Additive "H" concentrations of 0.01 to 0.05 per cent. At higher concentrations the effective permeability to oil decreased. After being stored in the reference oil for several months, the permeability of this particular test core increased to a higher value than was obtained during treatment.

The continued increase in effective permeability to oil following treatment has been observed in many of the cores treated. Fig. 4 shows a typical treatment curve which shows the additional increase in effective permeability to oil obtained during continued flushing of the test core with reference oil following treatment. As will be pointed out later, this behavior of core permeability has correlated frequently with the results of the field tests.

Data such as are shown in Figs. 1, 2, and 3 have indicated that Additive "H" concentrations as high as 0.5 per cent may be required in certain formations while much lower concentrations may be optimum in portions of the same formation or in other formations. Some dilution of the Additive "H" solution will normally occur in the well and within the formation, and to compensate for this dilution the trial use of a 1 per cent Additive "H" solution in crude oil was recommended.

It was realized that some over-treatment might occur in some formations or in parts of any specific formation. The data shown in Fig. 4 indicate that over-treatment in a given well might be indicated by a continuing productivity increase over an extended period following treatment. The oil-soluble nature of Additive "H" would permit over-treatment to be cleaned out during production after treatment and it appeared most desirable to use sufficient Additive "H" to insure adequate treatment rather than to risk under-treatment.

Criteria for Selection of Wells for Treatment

Limited experience indicates that wells can be selected for the treatment on the basis of fairly simple observations. Water blocking may be indicated by the following:

A. Decreased production after remedial work wherein water or any aqueous solution was used.

B. A decline in oil production while producing appreciable volumes of water.

Typical examples of the first would be a decreased production following killing a well with water or water base muds, or after workovers involving cementing where cement filtrates invade the formation, or following an acid job. The treatment may have some application in drill stem testing.

TABLE 1 — OIL-SYNTHETIC BRINE INTERFACIAL TENSION EFFECTS OF TYPICAL SURFACE ACTIVE AGENTS

Additive in Oil Phase	Interfacial Tension, Dynes/cm at Indicated Concentrations, Per Cent by Weight					
	.001	.005	.01	.05	.1	1.0
A. Diglycol Stearate	31.2	33.5	32.2	22.6	24.7	8.0
B. Sulforated Castor Oil	41.6	34.9	33.0	22.2	18.8	1.0
C. 2-Heptadecyl Imidazoline	1.7	0.9	0.6	*	*	*
D. Proprietary Compound	31.2	19.4	10.0	1.6	1.3	3.9
E. Proprietary Compound	31.5	31.5	26.9	7.4	0.5	2.1
F. Proprietary Compound	37.5	35.5	35.2	30.7	19.6	16.4
G. Proprietary Compound	33.4	16.8	9.3	0.6	0.2	0.2
H. Proprietary Compound	34.8	15.1	5.6	0.3	0.1	0.05
I. Proprietary Compound	24.0	7.9	1.0	0.05	0.05	0.05**
J. Proprietary Compound	3.2	1.6	0.8	0.4	0.1	0.05

*Not soluble to extent indicated.
**Not commercially available when investigation started.
Values of 0.05 dynes/cm are approximate values only.

TABLE 2 — WATER-BLOCK REMOVAL WITH PROPRIETARY AGENTS AND BEST SELECTED AGENT IN PARALLEL TESTS ON SEPARATE SPRINGER SAND CORES FROM THE EAST VELMA FIELD, OKLA.

Core No.	Equilibrium Permeability to Reference Oil, md: Before Water Blocking	After Water Blocking	After Treatment	Treating Agent	Per Cent Permeability Increase
1	28.3	2.1	4.3	Agent E	105
2	14.7	2.7	4.2	Agent E	56
3	30.6	6.4	8.2	Agent F	28
4	16.6	3.1	7.2	Agent F	132
5	49.6	8.8	37.9	Agent H	331
6	54.0	9.1	43.8	Agent H	381

TABLE 3 — WATER-BLOCK REMOVAL FROM CORES TREATED WITH PROPRIETARY AGENTS FOLLOWED BY BEST SELECTED AGENT

Core No.	Equilibrium Permeability to Reference Oil, md: Before Water Blocking	After Water Blocking	After First Treatment	After Second Treatment With 1% Additive "H"
1	28.3	2.1	4.3 (Agent E)	8.6
3	30.6	6.4	8.2 (Agent F)	27.0

The low cost of this treatment renders uneconomic any extensive well testing or engineering analysis to determine if a well is a suitable one for treatment. Often it is cheaper to try the treatment than to spend much time and effort in making a decision. This trial-and-error approach has been used to advantage in at least one field where extensive treatments have been made.

Field Results

General

The essential requirements for a successful water-block removal treatment, as indicated by laboratory results, would be met by applying an oil-squeeze treatment using a crude oil solution of Additive "H". The treatment consists of the injection of from 1,000 to 4,000 gal. or more of crude oil containing 1 per cent Additive "H" into a water-blocked formation. In one field, where the formational pressure is fairly low, the treatment is made by dumping the treatment solution into the annulus followed by sufficient crude oil to force the solution into the formation. Usually any low pressure conventional service company pumping equipment may be used. However, occasionally higher pressure pumps may be required. The crude oil containing Additive "H" is usually left in the formation an arbitrary time interval of 12 to 24 hours before production is resumed.

Ninety wells had been treated with the subject treatment by Mar. 1, 1954. Statistics compiled from the first 90 treatments are shown in Table 4.

While it has been apparent that a number of dry holes were treated unsuccessfully and a number of treatments were performed in wells where no water-block existed, it is believed that each of the 90 treatments was made with sufficient reason to try the treatment. Consequently, it is not anticipated that the ratio of successful treatments to unsuccessful treatments will increase with increasing numbers of total treatments so long as essentially random tests are used to establish the need for the treatment in various formations and fields.

Successful Treatments

Significant data obtained during a number of successful treatments are shown in Table 5. The particular successful treatments shown were picked partly on the basis of completeness of data, and partly on the basis that these wells exhibited several fairly definite varieties of water-block. To date, there has not been sufficient field experience with the method to give a reliable general answer to the question as to how long the beneficial effects may last. It may be noted on Fig. 5, however, that some of the wells continued to increase in production for several months after this treatment.

A few of the individual well histories involving successful treatments are outlined in more detail as follows:

Clinton field, Tex.: Well 1, producing from the Marginulina sand, had been repaired by cleaning out the wellbore, squeezing perforations to shut out water, drilling out and reperforating. Following workover, no appreciable production could be obtained. Sand was washed out of the hole and the well squeezed with 200 bbl of oil. No production could be obtained after two days swabbing. The well was then squeezed with 2,000 gal. of crude oil containing 20 gal. of Additive "H". Two days swabbing raised the fluid level to 2,300 ft and the casing pressure raised to 375 psi. Sand was washed out again and the well flowed 68 bbl wash oil in 12 hours. Later, on a repotential test, the well flowed 116 bbl oil and 3 BWPD with a GOR of 159.

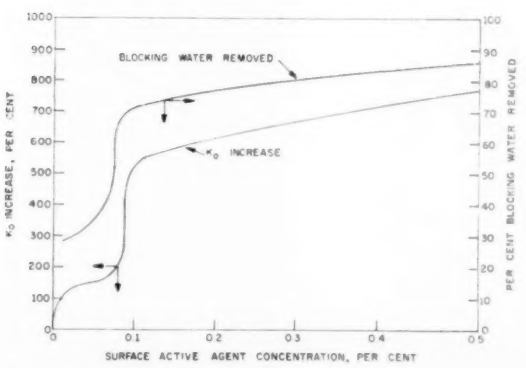
BLOCKING WATER REMOVED
K_o INCREASE
K_o INCREASE, PER CENT
PER CENT BLOCKING WATER REMOVED
SURFACE ACTIVE AGENT CONCENTRATION, PER CENT

FIG. 1 — WATER-BLOCK REMOVAL DATA, SPRINGER SAND CORE A.

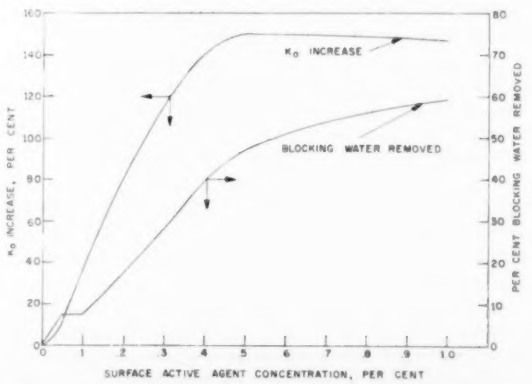
K_o INCREASE
BLOCKING WATER REMOVED
K_o INCREASE, PER CENT
PER CENT BLOCKING WATER REMOVED
SURFACE ACTIVE AGENT CONCENTRATION, PER CENT

FIG. 2 — WATER-BLOCK REMOVAL DATA, SPRINGER SAND CORE B.

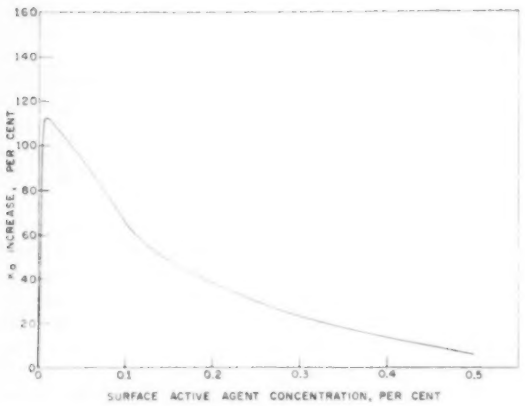

FIG. 3 — WATER-BLOCK REMOVAL DATA, CURTIS SAND CORE.

The water-block in this well is believed to have been caused in part by the production of water and mud prior to repairs and in part by cement and mud filtrate lost to the sand during repairs. Some mixed wettability characteristics have been observed in this sand during laboratory tests.

West Beaumont field, Tex.: Well II, producing from the Discorbis sand, had required casing repairs. Following repair operations, production could not be regained. Several cleanouts and screen repairs were attempted in an effort to regain production. Treatment was made by squeezing with 1,000 gal. of crude oil containing 10 gal. of Additive "H". Four days after treatment, the well produced 60 to 70 B/D salt water and oil base mud. Six days after treatment, swabbing produced 46 B/D salt water and 24 B/D oil. On the seventh day the well was trying to flow and 12 days after treatment the well flowed 20 B/D salt water and 67 B/D oil. One month after treatment, the well produced 27 B/D salt water and 63 B/D oil on gas lift. Several months after treatment, production was 84 B/D oil and 73 B/D water.

The water-block in this well is believed to have included mud filtrate, cement filtrate and formational water forced back into the oil producing zones during repairs. Oil base mud was used in later repair efforts but the evidence at hand indicates that the damage had been done prior to use of the oil base mud. Of particular interest is the fact that the treatment was applied to this well as a last resort treatment.

Hastings field, Tex.: Well VI was making 36 B/D oil and 10 B/D water when it died. Treatment with 1,000 gal. of crude oil containing 10 gal. of Additive "H" restored the well to flowing status. Productivity after treatment was 80 B/D oil and 20 B/D water.

Water-block in Well VI is believed to have been caused by formational water as were the water-blocks in Wells III, IV, and V shown in Table 5. The productivity of Well III increased over a 30-day period following treatment.

Goldsmith North Silurian, Tex.: Well IX was producing 38 B/D oil from the Silurian formation prior to a fracturing job using an acid fracturing fluid. Production declined to 28 B/D oil indicating some water-block has resulted from the acid-fracturing job. Treatment with 4,000 gal. of crude oil containing 1 per cent Additive "H" resulted in production of 66 B/D oil.

TABLE 4 — TREATMENT DATA

Total number of treatments	90
Number of successful treatments	39
Average treatment size, gallons treating solution per foot of formation treated	35
Average treatment cost, all wells	$430
Total productivity increase, BOPD	1,217
Average cost per barrel of increased daily production	$32

The water-block resulting from the presence of acid or spent acid is believed to have obscured the beneficial action of the acid-fracturing workover.

Midland Farms field, Tex.: Well XII was producing 12 B/D oil and no water from the Grayburg formation prior to treatment. Treatment was made with 5,000 gal. of crude oil containing 1 per cent Additive "H". Treatment was made down the annulus under vacuum and sufficient load oil was used to load the treating solution into the formation. Production immediately increased from 12 B/D oil to 40 B/D oil. Four months after treatment, the production had climbed slowly to 47 B/D oil.

The Grayburg formation in the Midland Farms field has been heavily acidized. It is possible that the water-blocks encountered in this field are partial water-blocks persisting after the last acid jobs were performed.

Each of the three Midland Farms' wells shown in Table 5, showed continued production increases over extended periods of time after treatment. Wells XIII and XIV were given the same treatment as was given Well XII. No production increase was observed immediately after treatment in either Well XIII or XIV. Treatment of each of these wells was considered a failure until production figures were obtained a month or more after treatment.

Fig. 5 shows the post treatment production from each of these Midland Farms wells. The delayed treatment response appears to correlate with laboratory test results as shown in Fig. 4.

Unsuccessful Treatments

Of 51 unsuccessful treatments, five treatments were made in dry holes. Two treatments were made in extremely low permeability gas producing formations.

At least 14 of the unsuccessful treatments were made in conjunction with other workover operations such

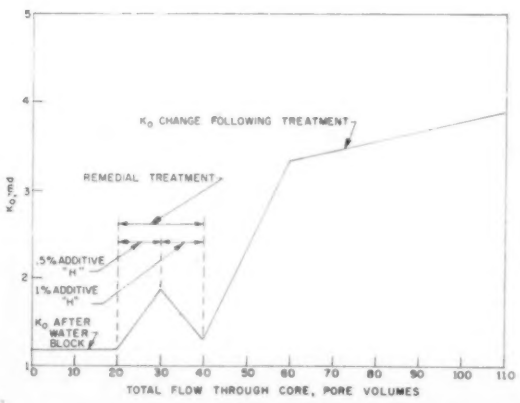

FIG. 4 — PERMEABILITY INCREASE FOLLOWING WATER-BLOCK REMOVAL TREATMENT, SPRINGER SAND CORE C.

TABLE 5 — REPRESENTATIVE SUCCESSFUL TREATMENTS

Field, Well	Formation	Treatment: Volume Gal.	Treatment: Pressure psi Max.	Production: Before Oil	Production: Before Water	Production: After Oil	Production: After Water	Increase Oil	Increase Water	Per Cent Increase Oil
Clinton, Tex.										
Well I	Marginulina	1,000	1,050	Negligible		116	3	116	3	Infinite
West Beaumont, Tex.										
Well II	Discorbis	1,000	1,000	Negligible		48	73	48	73	Infinite
Hastings, Tex.										
Well III	Frio	1,000	1,000	4	71	52	13	48	—58	1,200
Well IV	Frio	1,000	450	30	841	54	855	24	14	80
Well V	Frio	1,000	1,200	dead		75	266	75	260	Infinite*
Well VI	Frio	1,000	1,800	dead		80	20	80	20	Infinite**
Cedar Lake, Tex.										
Well VII	San Andres	5,000	0	31	0	46	0	15	0	48
Well VIII	San Andres	5,000	0	34	0	42	0	8	0	24
Goldsmith North, Tex.										
Well IX	Silurian	4,000		28	0	66	0	38	0	136
Hobbs, N. Mex.										
Well X	San Andres	4,000		5	32	65	49	60	17	1,200
Levelland, Tex.										
Well XI	San Andres	2,000	400	24	5	59	7	35	2	146
Midland Farms, Tex.										
Well XII	Grayburg	5,000	0	12	0	47	4	35	4	318
Well XIII	Grayburg	5,000	0	35	5	82	0	47	—5	1,340
Well XIV	Grayburg	5,000	0	39	3	59	0	20	—3	51
Winfield, Tex.										
Well XV	Mississippian			20	0	30	0	10	0	50

*This well was making 70 B/D oil and 211 B/D water when it died.
**This well was making 36 B/D oil and 10 B/D water when it died.

that failure to stimulate production could not be definitely ascribed to the treatment alone.

No data have been obtained as yet to indicate whether any of the treatment failures could have been due to insufficient treatment volume.

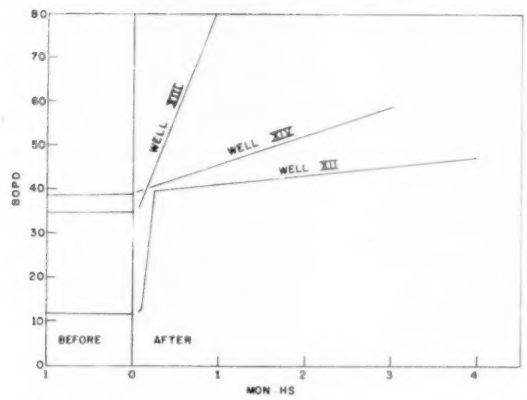

FIG. 5 — WELL PRODUCTIVITY INCREASE FOLLOWING REMEDIAL TREATMENT.

Cost

The cost per barrel of increased daily production is remarkably low. This cost has been $32/bbl of increase in daily production based on cost of all 90 treatments. Cost per daily barrel is only $14, if only the 39 successful treatments are considered. Average payout time for the treatments on these 39 wells was six days.

It is estimated that this type of water-block removal treatment, when offered and performed by the service companies, will be among the lowest cost well stimulation treatments now available.

Acknowledgments

Appreciation is expressed to the management of Stanolind Oil and Gas Co. for permission to publish this paper.

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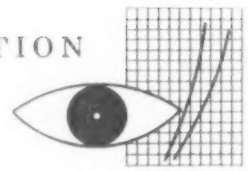
1. Larsen, D. H.: U. S. Pat. No. 2,465,237.

2. Muskat, M.: *Physical Principles of Oil Production*. McGraw Hill Book Co., (1949), 290. ★★★



R. W. TAYLOR | EDITOR
JOURNAL OF PETROLEUM TECHNOLOGY

More Technical Programs for Local Sections

Technical programs offered by local sections are the primary tools for inciting and maintaining the interest of the individual member in the Petroleum Branch. However, many local section program chairmen are finding it increasingly difficult to arrange monthly programs which will appeal to a large percentage of their members.

Field engineers, laboratory research engineers, and engineers who have advanced to management positions form three distinct groups evident in several local sections. Seldom does the program chairman secure a speech and speaker to interest a majority of those in each of these groups.

One step toward solving this problem of providing programs of interest for each group has been the offering of additional monthly technical programs through the formation of study groups. These have been very successful in some section, very unsuccessful in others. This lack of success of some study groups can be attributed to the assignment of all responsibilities of the meetings to one man, often the section program chairman. Handling the publicity, the meeting arrangements, and the program is more of a job than one man can continually carry out without difficulty.

Pacific Junior Group

In order to provide additional technical meetings for a membership of diversified interests, we feel that many local sections could profitably adopt a plan similar to the one now followed by the Pacific Petroleum Chapter Junior Group. This organization has its own officers and functions independently of the Pacific Petroleum Chapter insofar as sponsoring technical programs. David K. Hayward of the Texas Co., secretary of the Junior Group, explains its workings in this manner:

"The organization was formed in 1938 in order to provide a forum to discuss technical matters at the level of the younger engineer. It was the feeling among the originators of the group that the local section, which concentrated quite heavily on papers dealing with mining and metallurgy, did not fill the need of the young petroleum engineer.

"During 1954 the average attendance has been in excess of 100 persons per meeting. Peak attendance was 165 at the August meeting on artificial lifting. It has been found that the functioning of the Junior Group has not split the allegiance of the membership of the Pacific Petroleum Chapter, but has bolstered the attendance and increased the membership of the parent organization.

Oil Production Fundamentals

"In planning the monthly programs, both in 1938 and now, an attempt has been made to offer information on subjects which deal with methods of oil production fundamentals in use, but specialized to the extent that insufficient treatment is given in the university curriculum.

"The program is usually conducted as a symposium in which three or four phases of a particular subject are presented. The symposium-type program limits the time of each speaker, so that speakers need not spend an unreasonable amount of time in preparation and so their talks will be a digest of the most pertinent points of the subject. Typical subjects have been completion fluids, drainholes, state registration of engineers, artificial lift, reserve estimation, and in-situ combustion. The November program was a symposium on formation logging methods. It featured the following talks by representatives of the listed companies: "Microlog" by Schlumberger; "Guard Log" by Halliburton; "Neutron Log" by McCullough; "Gamma Log" by Lane-Wells; "California Formation Well Logging" by Baroid; and "Optimum Use of Formation Logging" by Formation Logging Service.

"The handling of finances for the Junior Group is very simple. The cost of mailing notices is virtually the only expense, and this is paid by the Pacific Petroleum Chapter."

A Plan to Consider

The Pacific Junior Group does not function as a study group in that it does not hold series of sessions on the study of a single subject. However, other local sections could easily adopt the general plan of organization of the Junior Group for functioning as a symposium-type forum for field or reservoir engineers, as a study group, or as a combination of both — holding a study series, then changing pace with a few symposium-type programs. With its own group of officers working toward a strong organization, a successful technical group could be built. Probably a less restrictive name than "junior group" would be appropriate for such organizations, although no objections have been raised to this on the Pacific Coast.

We commend this plan of an additional group designed to provide more technical programs to all local sections now faced with the problem of serving a membership of diversified interests. ★★★

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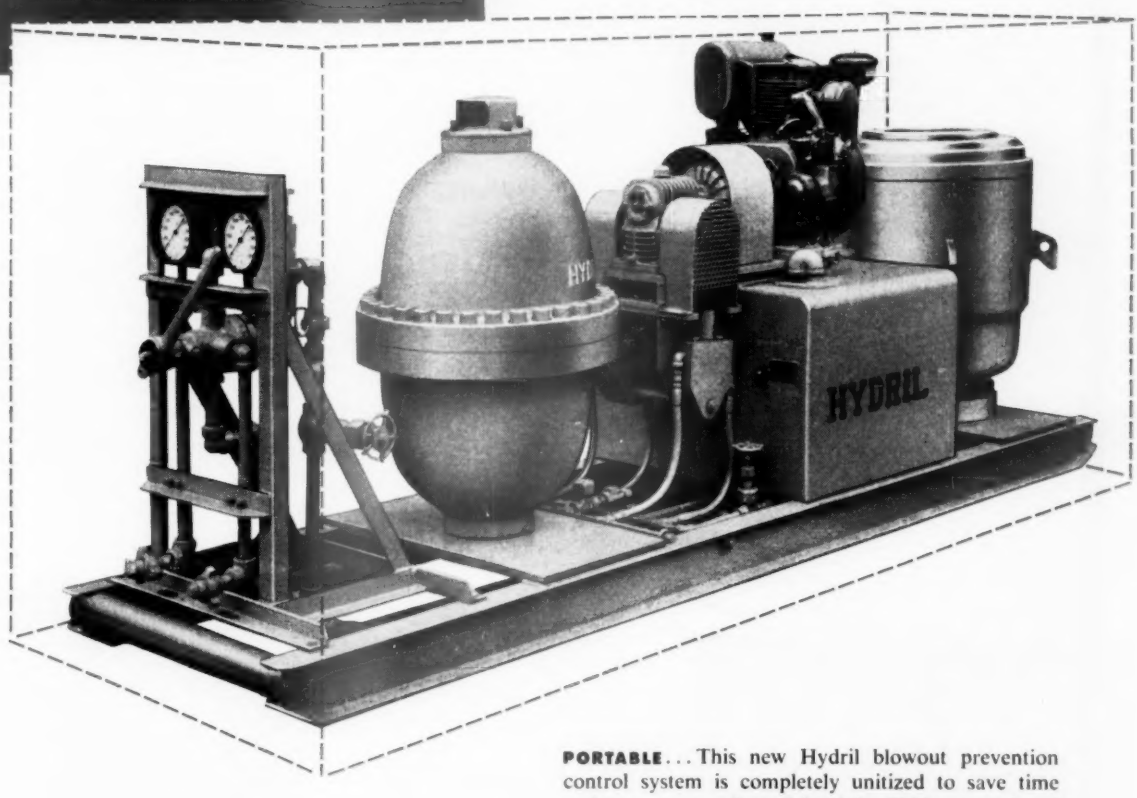

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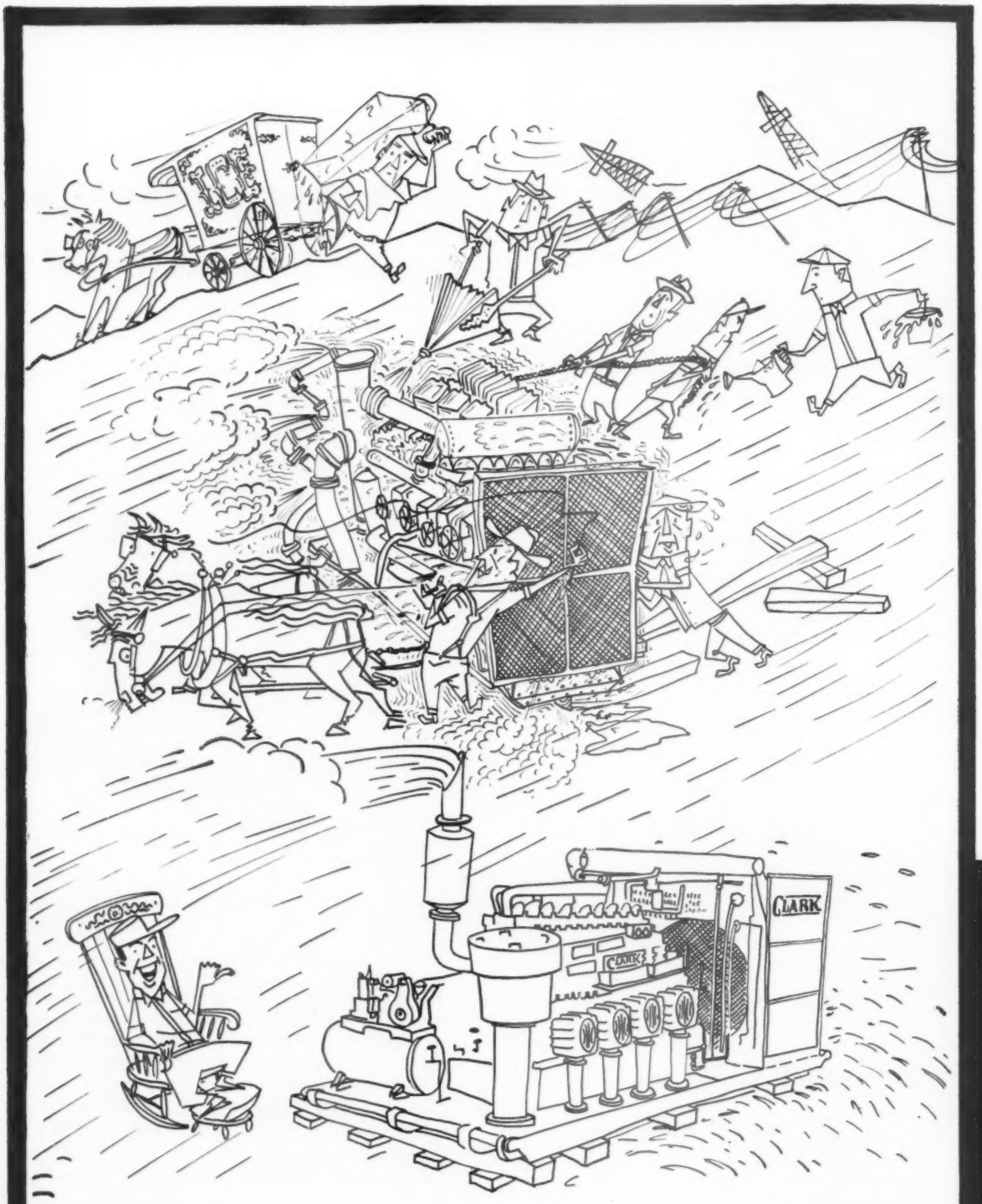

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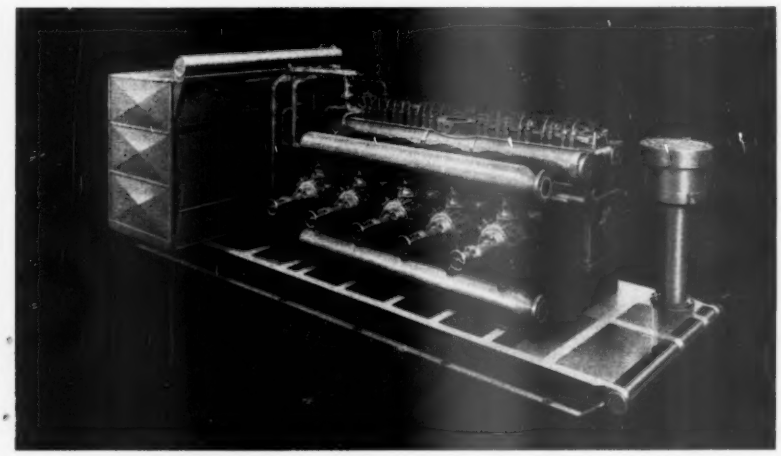

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RÉSUMÉ of 1954 EXECUTIVE COMMITTEE ACTIONS GIVEN by BRANCH CHAIRMAN

JOHN R. McMILLAN*

CHAIRMAN
PETROLEUM BRANCH, AIME

This talk was presented at the first annual Membership Luncheon held on October 19 at the Petroleum Branch Fall Meeting in San Antonio.

The purpose of this luncheon is for us to set aside a period during our annual Fall Meeting in which your officers can report to you on the current activities of the Petroleum Branch and the Institute, and to provide an opportunity for you as members to discuss matters of interest on an open forum basis with the Executive Committee. Today we are going to attempt to bring you up to date on the business of your Petroleum Branch.

As you will see from this report, we are a growing group of professional men in the Petroleum Branch of AIME, now running a budget of $200,000 per year. This makes us a pretty fair sized little business organization, the current affairs of which merit your thoughtful attention as members.

Finance

The Petroleum Branch operates on an independent budget within the framework of the over-all AIME budget, with all of the accounting and money handling done by the New York headquarters of the Institute. All of our income is credited directly to us and our expenses are charged against us. We share in certain expenses of the Institute headquarters in proportion to our membership, along with the other two branches. For 1954 the proration is: Petroleum Branch, 26.5 per cent; Mining Branch, 48.5 per cent; and Metals Branch, 25 per cent.

For the year 1954, we expect a total income for the Petroleum Branch of approximately $197,000. This income will average $30 per Petroleum Branch member and comes from the following sources:

Membership dues	56 per cent
Advertising and publication sales (31 per cent of this is PETROLEUM TECHNOLOGY advertising revenue)	42 per cent
Miscellaneous	2 per cent

For this year we expect the Branch expenses to be about $195,000 in the following categories: (This puts us in the black by $2,000 for 1954.)

Membership service: Assistance to local sections, Petroleum Branch office, membership promotion, etc.	27 per cent
Publications: PETROLEUM TECHNOLOGY, *Transactions, Statistics,* Directory	52 per cent
Our Share of Institute headquarters in New York: Secretary's office, business office, pensions, insurance, depreciation	21 per cent

*President, Fullerton Oil Co., Pasadena, Calif.

It has been the fundamental principle of the Petroleum Branch that each branch of the AIME should pay its own way and stay in the black. Our income has increased from $123,000 in 1950 to an expected $197,000 in 1954, or an increase of 60 per cent. During the same period, we have had a very large increase in membership and activity of the Petroleum Branch, and your Executive Committee has felt it desirable to reinvest the major portion of our increased income in taking care of this expansion and laying the foundation for future growth. Under this plan we have been in the black with a nominal surplus each year since 1950. We believe that during the next three years we have an excellent chance of accruing a sizeable surplus which will be used to build up the financial reserve of the Petroleum Branch.

Membership

As a result of an intensive membership campaign, we have received 616 new applications for membership through September 30 of this year, as against 408 applications last year, a 51 per cent increase. We now have 6,500 members, excluding student associates, in the Petroleum Branch. (For comparison we had 3,616 members of this type in August, 1950.) We will have spent some $5,000 on this campaign and, with this fact in mind, we suggest that you coordinate this effort in your own local sections to take advantage of the Dallas membership promotion.

A large part of our growth has been due to the establishment of new sections. The AIME by-laws have been changed to permit the formation of overlaying local sections of the various branches. We have taken advantage of this change to form new local sections and bring our total to 22 petroleum local sections and two petroleum chapters.

The creation of these new Petroleum Sections has been undertaken solely to enable us to serve our membership so that small geographical groups can meet without traveling 200 miles to a meeting site. We are not trying to increase our representation on the Council of Section Delegates or otherwise. In fact, your Executive Committee is on record as favoring one representative from the Petroleum Branch to express the views of our own sections in New York.

Our Branch secretary predicts we will have 11,000 members and student associates by 1960.

Advertising

The current objective of your Executive Committee is to develop advertising in the JOURNAL OF PETROLEUM TECHNOLOGY to the point where the magazine will be

self-supporting. In 1953, Joe Alford made up a chart for us to calculate when this point would arrive. Using a 50-page per year growth, he found it to occur in 1957. We expect to show a net return of $63,000 this year on our advertising as against $46,000 last year. The growth in advertising is shown clearly by the fact that we had 98 pages in the year 1950 as against an anticipated 300 pages for 1954. You realize, of course, that the advertiser must receive a business return to justify his expenditure in PETROLEUM TECHNOLOGY, and these facts show that he must be receiving it.

A sales promotion campaign featuring seven pieces of literature has been presented to our potential advertisers and advertising agencies this year to make them more aware of what PETROLEUM TECHNOLOGY has to offer. We spent $4,000 on this campaign. You may wonder why we stress advertising growth, and, briefly, this is why: Without advertising we would have to raise our dollar income by 31 per cent to enable us to publish our technical papers in the manner to which we have become accustomed. This would mean higher dues (probably $5 to $10 per member), which we do not think we want. Under our plan we will eventually have 45 per cent advertising and 55 per cent editorial matter — no more, as compared to the usual trade magazine ratio of at least 60 per cent advertising. We want the membership to know about these matters, and we welcome your sentiments on the policies followed to date.

The Magazine

Of course, the reason for this aggressive advertising effort is to serve the members with the best editorial material possible in their magazine. You probably noticed that we have made some changes in the magazine and its cover. Among these changes are easier to read typefaces throughout, insertion of pieces of art to provide relief, and rearrangement of the editorial matter in a functional manner with advertising placed in specific spots for maximum visibility.

Our purpose in creating this new design is to help the magazine do the best possible job in its particular field — the technical literature and professional functions of petroleum engineering. We are making a special effort through Glenn M. Stearns and his General Editorial Committee to publish articles that give practical and usable information — not necessarily original or new ideas. These are in addition to the *Transactions* papers. Since we are not a commercial publication, we will not attempt to publish such things as oil industry news, and we will limit the pages to the material which properly falls within the scope of petroleum engineering. We want to make the magazine so attractive that the petroleum engineer will feel that he cannot afford to be without it, which will further encourage membership.

Special Projects Fund

Most of you know that the Petroleum Branch owns a fund entirely apart from Institute finances that is called the "Special Projects Fund" and is operated from the Petroleum Branch office in Dallas. The main sources of income to this fund are from the sale of exhibit booths and registration fees at our Fall Meetings and from other projects undertaken as a Branch enterprize.

In general, the purpose the Fund is to provide means for any action favored by the Executive Committee for which other funds are not available. The fund in no way competes for revenue with projects of the Institute and is not to be used in conflict with the by-laws of the Institute.

At the close of 1953, this fund contained $22,028.27. During 1953 it handled over $15,000 of income and also disbursed a similar amount in expenses — mostly in connection with the AIME Annual Meeting in New York and the Branch meeting in Dallas.

By the end of 1954, we expect to build this fund to $33,000. With our Annual Meeting costing about $40,000 currently, we feel that we need a healthy backlog in this fund.

You will be interested to know that we have used this fund to finance our Fall Meetings, to assist local sections, to reprint *Transactions* volumes, to print the *Transactions Index* that was recently released, and for other worthwhile projects that could not otherwise be undertaken. It has been used many times to help new local sections establish themselves.

New York and Institute Management

The aims of the Petroleum Branch are in harmony with the aims of the AIME. I believe we currently have a better understanding and feeling of mutual cooperation with the AIME Board of Directors than at any time for several years. I think our Board is doing an excellent job.

The Board is composed of representatives of each Branch of the Institute, in ratio to the membership, and the Petroleum Branch is now represented on the AIME Board by Lloyd E. Elkins and Harold Decker as Institute vice-presidents, by M. L. Haider, Carl E. Reistle, Jr., and E. C. Babson as directors, and by Gail F. Moulton as Institute treasurer.

Finale

You are, of course, aware that no one person is responsible for our over-all progress. It has been the outgrowth of the thinking of several Executive Committees and Branch Chairmen. We merely set the policy — the actual work and a great many of our ideas stem from Joe Alford and his excellent staff. Joe is what I would call a business manager of our organization and we look to him for assistance every way we turn. I wish to extend my thanks to the staff for their cooperative spirit and especially to Joe for his untiring aggressiveness.

In general, your Executive Committee is pleased with this progress. At the same time, however, we have received some objections to the procedures we are now following, and, therefore, we must hear from you as members. This brings us down to one of the main purposes of the luncheon meeting today — to answer any questions you may wish to ask.

No questions were received from the floor following McMillan's talk. This same privilege of asking questions or expressing opinions on the policies set by the Executive Committee is offered to all of our readers. ★★★

PICTORIAL REVIEW of

Another Record-Breaking Attendance

The 1954 Petroleum Branch Fall Meeting, the highlight of the year for Petroleum Branch, AIME members, fulfilled all expectations of the 2,302 persons who attended. The meeting was held from October 17 through October 20 in San Antonio.

This total attendance mark broke the record set last year in Dallas by a small margin. The largest difference in the 1953 and the 1954 attendance was the increase in the number of ladies present.

Three concurrent sessions each morning and two concurrent sessions each afternoon provided ample opportunity for all in attendance to hear presentations of technical papers of interest to them. Social activities in the form of luncheons, a western party, and a dinner-dance were well attended.

Registration and Committee Day

Sunday, October 17, was registration and committee meeting day. While the early arrivals moved through the registration process, Branch committees were meeting in several parts of the hotel to discuss local section activities, publications, and AIME business in general.

The bulk of the crowd descended on Monday morning. The fast-moving registration lines trailed throughout the exhibit area in the Plaza Hotel Ballroom, but the three technical sessions already underway drew large attendances. The afternoon technical sessions attracted even larger crowds.

Reading from left to right across the top of the page, the scenes are: (1) the lobby at convention headquarters in the Plaza Hotel; (2) more crowds and conversations around the AIME membership booth on the mezzanine floor of the Plaza; (3) fast-moving registration lines in the Plaza Ballroom; and (4) the head table at the Welcoming Luncheon. Seated from left to right at the head table are: Joe B. Alford, Branch executive secretary; Mrs. and Mr. Kenneth S. Ferguson, father of Cedric K. Ferguson, who received posthumously the first presentation of the Cedric K. Ferguson Medal; Chester L. Wheless, of LaGloria Oil and Gas Corp., chairman of the Southwest Texas Local Section; Tom Sealy, speaker at the luncheon; Paul R. Turnbull, Welcoming Luncheon general chairman; and John R. McMillan, Petroleum Branch chairman.

BRANCH FALL MEETING

Sealy Speaks at Luncheon

Tom Sealy, a member of the Midland law firm of Stubbeman, McRae, and Sealy and chairman of the Board of Regents of the University of Texas, was the main speaker at the Monday Welcoming Luncheon. Paul R. Turnbull, Del Mar Drilling Co., was the general chairman of this luncheon which drew a capacity attendance to both the ballroom in which it took place and to the one in which it was televised.

The Monday night Frontier Party at McArthur Park brought forth a large crowd in Western attire for a barbecue supper as well as round and square dancing.

The technical sessions continued on Tuesday through the morning and afternoon. A Membership Luncheon attracted another capacity crowd to hear John R. McMillan give a report on the actions of the Branch Executive Committee during the past year. This report is published on pages 22 and 23 of this issue. The evening dinner-dance at Club Sevenoaks featured the orchestra of Hal McIntyre.

New Orleans in '55

Wednesday was another full day of technical sessions with the presentations of the last 45 papers on the program being completed around 4 p.m. The mass exodus was already underway.

The 525 ladies in attendance had meanwhile enjoyed a full schedule of social events throughout the convention. Several revealed plans of getting an early start in persuading their husbands to take them to New Orleans for the 1955 Fall Meeting.

R. W. TAYLOR

The center photographs are scenes from the Welcoming Luncheon (top) and the Ladies' Style Show.

Across the bottom of the page, from left to right, are pictured: (1) presiding chairmen at a technical session, W. E. Richards of Rock Hill Oil Co. (seated), and A. L. Vitter, Jr., of The California Co.; (2) Joe B. Alford presenting the Cedric K. Ferguson Medal to the recipient's father, Kenneth S. Ferguson, at the Welcoming Luncheon; (3) the Ladies' Welcoming Merienda at Brackenridge Park; and (4) the Frontier Party at McArthur Park.

Several of these photographs were furnished through the courtesy of Dresser Industries.

PACIFIC FALL MEETING ATTRACTS 528 PERSONS

Registration totals reached 528 persons at the Pacific Petroleum Chapter Fall Meeting held in Los Angeles on October 7 and 8. This larger-than-usual crowd for the Pacific Meeting had the opportunity of hearing the presentation of 12 technical papers, including a special session on drainhole drilling.

Of the 528 persons who attended, 326 were AIME members, 10 were Student Associates, and 192 were non-members. In addition, several hundred mining and metallurgical engineers were on hand for the Mining and Metals Branch meetings, held yearly in conjunction with the Pacific Petroleum Chapter Fall Meeting.

Technical sessions on formation fracturing, fluid injection, engineering and management, oil field performance, and drainhole drilling were well attended.

READING CLOCKWISE AROUND THE PHOTOGRAPHS—At the top, the familiar registration line moves along. Next, R. S. Crog, Union Oil Co., Program chairman for the Pacific Meeting, submits a question to be answered at the *Panel Discussion on Drainhole Drilling*. The bottom photograph shows a small part of the exhibit area in the Biltmore Hotel where a total of 31 exhibitors had booths. A high level conference is pictured in the last photograph, with Charles E. Beecher, Cities Service; John R. McMillan, Fullerton Oil Co., Branch chairman; Joe B. Alford, Branch executive secretary; and Milton E. Loy, Schlumberger, Pacific Petroleum Chapter chairman, participating.

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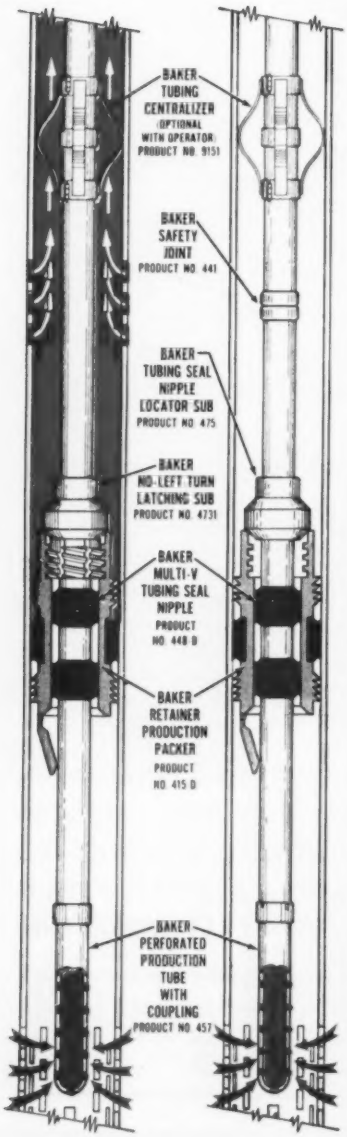
BAKER TUBING CENTRALIZER (OPTIONAL WITH OPERATOR) PRODUCT NO. 9151
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BAKER NO-LEFT TURN LATCHING SUB PRODUCT NO. 4731
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BAKER RETAINER PRODUCTION PACKER PRODUCT NO. 415 D
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Typical Dual Zone Hookup

Typical Single Zone Hookup

Do you know that with only ONE Baker Retainer Production Packer you can equip your well for *either* SINGLE ZONE or DUAL ZONE production? And that you can accomplish *any* type of completion for *any* method of production to meet *fixed* or *changing* well conditions?

A single Baker Retainer Production Packer will also outperform many specialized tools when used as a TESTING PACKER – SQUEEZE PACKER – GAS LIFT PACKER – PERMANENT COMPLETION PACKER – WATER FLOOD PACKER – GAS INJECTION PACKER – CORROSION CONTROL PACKER – TUBING ANCHOR – ONE-WAY BRIDGE PLUG – PERMANENT BRIDGE PLUG.

Every production man should be familiar with the many operating advantages of this "Universal Type" Packer, which include . . .

WIRE LINE SETTING – The packer can be set with *wire line speed and accuracy*, using the same set-up just used for perforating. The Baker Packer also can be set on drill pipe or tubing.

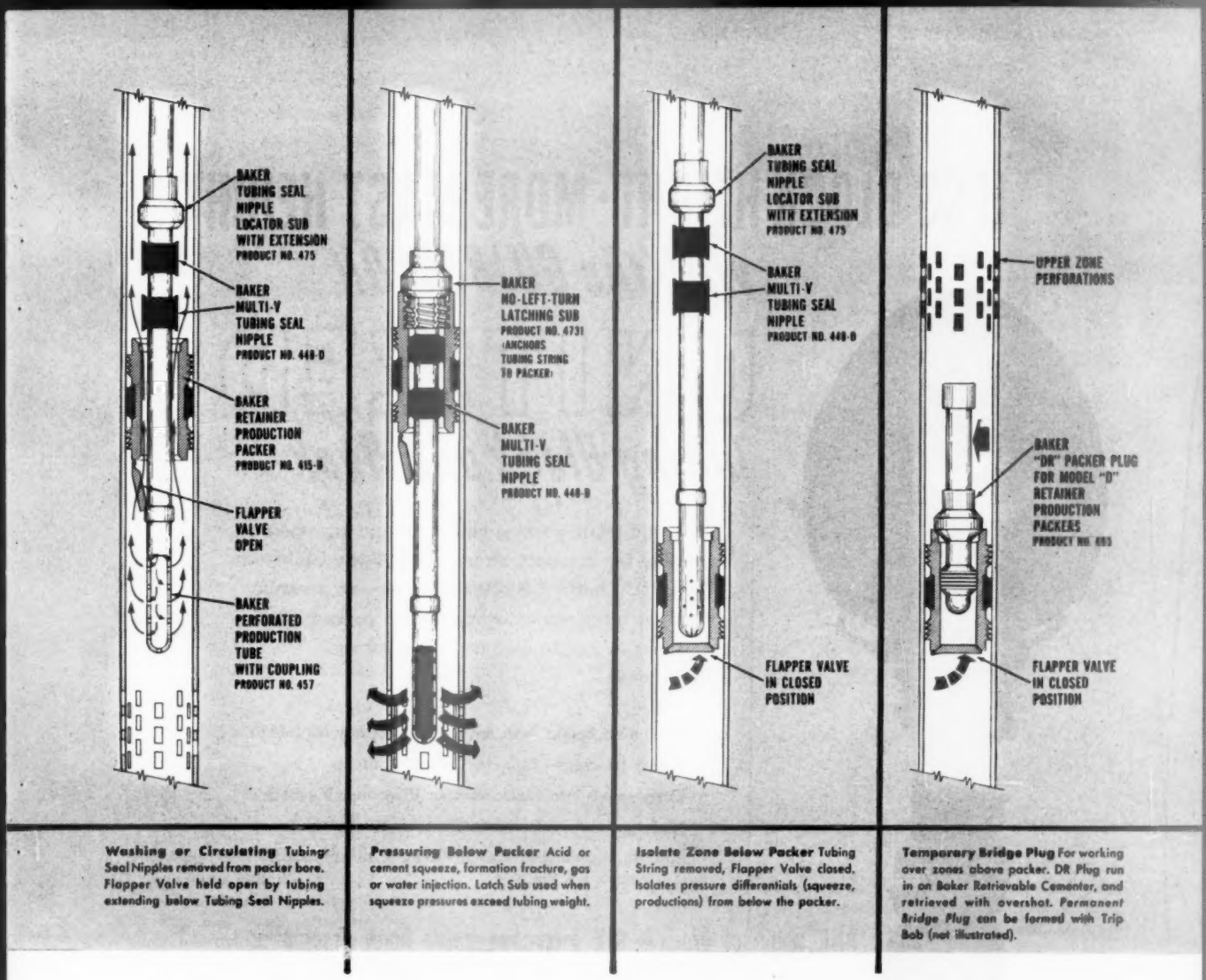
SETTING UNDER HIGH PRESSURE – By using a lubricator, the Baker Retainer Production Packer can be set under high pressure. From the moment it is set, the self-contained, flapper-type, back-pressure valve closes and isolates pressure below the packer.

TUBING STRING IS ALWAYS "FREE" – That valuable string of tubing – whether 1,000 feet or 16,000 feet in length – can be removed by simply picking up the tubing weight.

EXCESSIVE "SET-DOWN" WEIGHT OR TENSION NOT REQUIRED – Even when squeezing, formation fracturing, or producing at any depth under pressure, a perfect pack-off is maintained independent of excessive set-down weight, or tension.

HOLDS PRESSURE DIFFERENTIALS FROM ABOVE OR BELOW – Two sets of opposed slips, and a resilient packing confined by lead and metallic sealing rings, effect a permanent pack-off that will hold any pressure differential *either from above or below the packer* that is safe for the well equipment.

PACKS-OFF AND HOLDS UNDER HIGH BHT – Baker Retainer Production Packers will hold high pressures under conditions of high temperatures. Hundreds of Baker Packers are in successful service in Southwest and Gulf Coast areas where temperatures in excess of 300 degrees are not uncommon.


BAKER TUBING SEAL NIPPLE LOCATOR SUB WITH EXTENSION PRODUCT NO. 475
BAKER MULTI-V TUBING SEAL NIPPLE PRODUCT NO. 448-D
BAKER RETAINER PRODUCTION PACKER PRODUCT NO. 415-D
FLAPPER VALVE OPEN
BAKER PERFORATED PRODUCTION TUBE WITH COUPLING PRODUCT NO. 457
BAKER NO-LEFT-TURN LATCHING SUB PRODUCT NO. 473 (ANCHORS TUBING STRING TO PACKER)
BAKER MULTI-V TUBING SEAL NIPPLE PRODUCT NO. 448-D
BAKER TUBING SEAL NIPPLE LOCATOR SUB WITH EXTENSION PRODUCT NO. 475
BAKER MULTI-V TUBING SEAL NIPPLE PRODUCT NO. 448-D
FLAPPER VALVE IN CLOSED POSITION
UPPER ZONE PERFORATIONS
BAKER "DR" PACKER PLUG FOR MODEL "D" RETAINER PRODUCTION PACKERS PRODUCT NO. 493
FLAPPER VALVE IN CLOSED POSITION

Washing or Circulating Tubing Seal Nipples removed from packer bore. Flapper Valve held open by tubing extending below Tubing Seal Nipples.

Pressuring Below Packer Acid or cement squeeze, formation fracture, gas or water injection. Latch Sub used when squeeze pressures exceed tubing weight.

Isolate Zone Below Packer Tubing String removed, Flapper Valve closed. Isolates pressure differentials (squeeze, productions) from below the packer.

Temporary Bridge Plug For working over zones above packer. DR Plug run in on Baker Retrievable Cementer, and retrieved with overshot. *Permanent Bridge Plug* can be formed with Trip Bob (not illustrated).

RESISTS CORROSION—The cast-iron used in the construction of Baker Packers is far more resistant to corrosion than the casing in which the packer is set, thus making it ideal for permanent installations, or for use in areas plagued with a severe corrosion problem.

EASILY DRILLABLE—The Baker Packer is constructed of drillable cast-iron, and its design supplements the breaking-up action of the bit. Whether it has been in the well for only a few hours, or for ten years, the Baker Packer can be drilled up in minimum time. Expensive and hazardous "milling-out" operations never are required.

IMPORTANT FACTS

Baker Packers are used in a majority of installations where conditions of extreme pressure, temperature, or depth are present. Baker Packers also dominate Dual Zone installations, particularly those involving two-packer, crossed-flow arrangements.

BUT IT IS ALSO TRUE that *more* Baker Packers are used for *simple single zone* completions than for *any other type of completion*, and that *most* Baker Dual Zone installations employ *only one* packer.

Ask any Baker representative, or office, for complete details, as well as your copy of the recent Baker Equipment News dealing with DUAL ZONE COMPLETION PRACTICES. There is no charge, and no obligation, for specific recommendations and completion planning advice available from Baker Technical Advisers. Why not be prepared for your next completion?

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IT'S WORTH COMPLETING WELL,
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RETAINER PRODUCTION PACKER

LESS BLOCK HEIGHT - MORE MAST HEIGHT

with the GUIBERSON

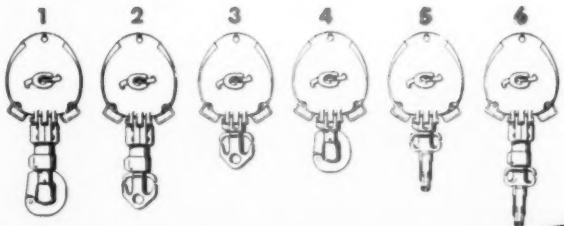
UNITIZED

Tubing Block and Hook

You add extra working height to your rig when you use the compact, streamlined 45-ton Guiberson Type "A" Unitized Block and Hook—an assembly that has more work-saving features packed into less over-all height than any other tubing block made.

- **Maximum height** with any hook assembly 60 inches
- **Finest bearings**—falls fast, won't foul up
- **Lines reeve** into block without disconnecting hook
- **"Safety link"** latches into hook, can't disengage
- **Smooth, streamlined design**—3 to 1 safety factor on yield

ONE *compact block*—SIX *interchangeable hook assemblies* *in SINGLE or DOUBLE SHEAVE*



1 Block and Spring Hook Assembly
2 Block and Spring Duplex Hook Assembly
3 Block and Short Duplex Hook Assembly
4 Block and Short Hook Assembly
5 Block and Short Triplex Hook Assembly
6 Block and Spring Triplex Hook Assembly

Better Be Safe Than Sorry!

SAFE THAN SORRY BETTER BE GUIBERSON

THE

GUIBERSON

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Sold By Leading Oil Field Supply Stores Everywhere

A ROTATIONAL HIGH PRESSURE VISCOSIMETER

MURRAY F. HAWKINS, JR.
MEMBER AIME

MARION L. KIMMEL
JUNIOR MEMBER AIME

LOUISIANA STATE UNIVERSITY
BATON ROUGE, LA.

INTRODUCTION

Sage[1] appears to have been the first (1933) to design a rolling ball viscosimeter for the express purpose of measuring the viscosity of oils with natural gas in solution, i.e., under reservoir conditions. In 1940 Hocott and Buckley[2] further refined the rolling ball instrument in both design and method of operation, and their instrument, known as the Humble type, was the forerunner of present day viscosimeters used in petroleum production and research laboratories. They also initiated the technique of charging the viscosimeter with a sample directly from a bottom hole sampler.

In 1948 the committee on engineering research of the Petroleum Division of the AIME in Part 3 (1) of the Physical-Chemical Topics of Table 1 suggested the "development of improved and simpler methods of measuring viscosity of reservoir fluids." This note will describe a rotational, high pressure viscosimeter which has been developed in response to this suggestion but whose relative merits are yet to be determined fully.

THE INSTRUMENT

Fig. 1 is a photograph and Fig. 2 is a cross sectional drawing of the instrument. It consists of a non-magnetic, stainless steel rotor about 4 in. in length and 1 in. in diameter centered axially within a non-magnetic, stainless steel, pressure vessel of cylindrical bore. The rotor is mounted on miniature, precision ball bearings and has a radial clearance of about 1/64 in. Alnico magnets are inserted perpendicular to the axis of rotation on either end of the rotor, those at the top to serve as indicator magnets, those at the bottom, as the driven magnets which turn the rotor. A constant (but variable) speed motor outside the pressure vessel turns the rotor by means of a driving magnet attached to the motor shaft. The motor speed is checked using an aircraft type, precision, spring-wound interval timer and an electric impulse counter to record revolutions by means of an electric contactor on the motor shaft.

Fluid Viscosity Measurement

The fluid viscosity is measured at constant rotational speed in terms of the distance (screw turns) the driving magnet must be withdrawn from the rotor magnets before a break in the magnetic linkage occurs, that is, when the viscous torque exerted by the fluid on the rotor just exceeds the torque between the magnets. This break is precipitous and is easily detected by observing the motion of a magnetized needle suspended outside the pressure vessel near the indicator magnets in the top of the rotor.

Rotor speeds and clearance between rotor and stator were selected from tests[3] to insure laminar flow, which generally obtains in the reservoir. While the upper and lower limits of the viscosity range are yet to be determined, it is known that they can be extended considerably beyond those indicated in Fig. 3 by changing the clearance, using insert cylinders for example, and/or by changing the speed of rotation. The instrument has a capacity of about 40 cc and is designed to measure absolute viscosity.

The pressure coefficient in the present instrument was made negligible for the range of pressures used by selecting a pressure vessel of sufficient wall thickness

Manuscript received in Petroleum Branch offices on May 6, 1954.
[1]References given at end of paper.

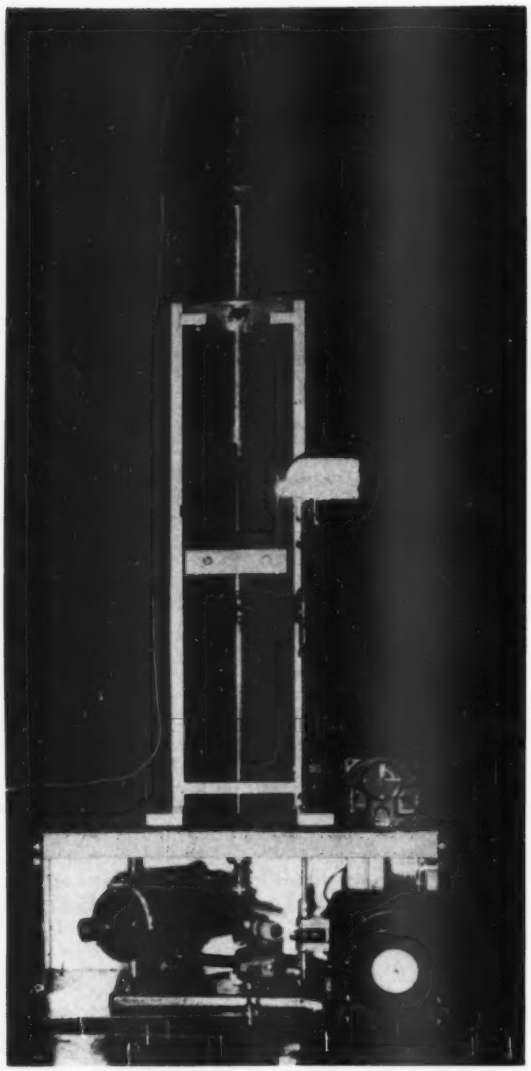

FIG. 1 — PHOTOGRAPH OF THE HIGH PRESSURE ROTATIONAL VISCOSIMETER.

(½ in.), as an alternative to using an insert cylinder on which internal and external pressures may equalize. The temperature coefficient was made small by manufacturing the rotor and stator of the same material. The aging coefficient of the Alnico magnets is known to be very low; however, bearing wear, although not observed in some 50 hours of testing, will certainly call for periodic calibration.

CALIBRATION CURVE

Fig. 3 is a calibration curve performed at atmospheric pressure and room temperature using fluids supplied by the U. S. Bureau of Standards and other fluids of known viscosities. No temperature controlled jacket was provided for the present instrument, and all measurements were made at room temperature. Corrections for small temperature variations from 80° F were made using known or estimated temperature coefficients of viscosity for the liquids.

Fig. 4 is a measurement at elevated pressures on a 35° API oil sample using pure methane for the dissolved gas. As the gas was dissolved in the oil in the instrument, pressures above saturation were not obtainable without mercury entering the vessel. This limitation would not exist, of course, in the case of a sample transferred from a bottom hole sampler or storage vessel. Check measurements with a Humble type rolling ball instrument at the higher pressures gave satisfactory agreement. Tests indicate a rapid attainment of equilibrium following a pressure change during which the rotor was kept in motion. No difficulties were encountered with escaped gas bubbles lodging between the rotor and stator. The five measurements of Fig. 4 were completed in less than an hour, several duplicate readings of good reproducibility having been taken at each point.

While no claim is made for a finished, commercial instrument, and while several refinements, improvements, and simplifications are now obvious, tests indicate that a new type pressure viscosimeter has been developed which satisfactorily measures reservoir oil viscosity.

ACKNOWLEDGMENT

Appreciation is expressed to the Humble Oil and Refining Co., who, although in no way connected with this work, established a graduate fellowship in the Petroleum Engineering Department under which this study was conducted.

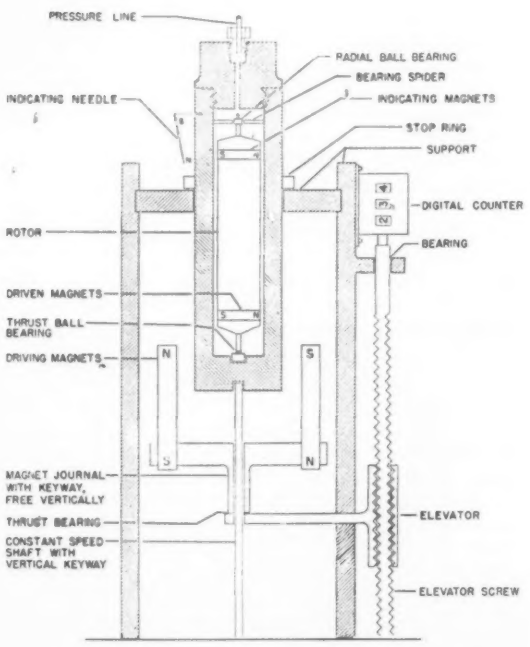

FIG. 2 — SKETCH OF PRESSURE VISCOSIMETER.

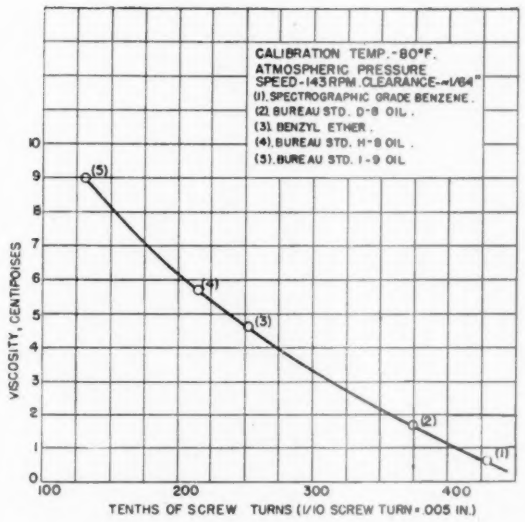
CALIBRATION TEMP. - 80°F.
ATMOSPHERIC PRESSURE
SPEED - 143 RPM CLEARANCE - ~1/64"
(1). SPECTROGRAPHIC GRADE BENZENE.
(2). BUREAU STD. D-8 OIL.
(3). BENZYL ETHER.
(4). BUREAU STD. H-8 OIL.
(5). BUREAU STD. I-9 OIL
VISCOSITY, CENTIPOISES
TENTHS OF SCREW TURNS (1/10 SCREW TURN = .005 IN.)

FIG. 3 — CALIBRATION CHART FOR ROTATIONAL HIGH PRESSURE VISCOSIMETER.

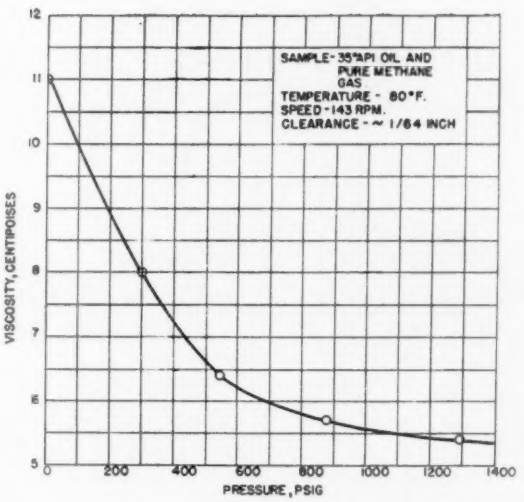
SAMPLE - 35°API OIL AND PURE METHANE GAS
TEMPERATURE - 80°F.
SPEED - 143 RPM.
CLEARANCE - ~ 1/64 INCH
VISCOSITY, CENTIPOISES
PRESSURE, PSIG

FIG. 4 — VISCOSITY OF A 35° API OIL WITH METHANE SOLUTION GAS AS A FUNCTION OF SATURATION PRESSURE.

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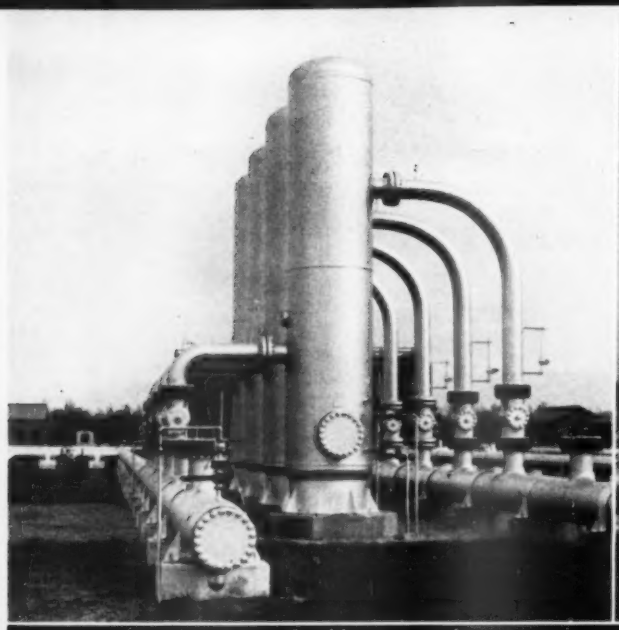
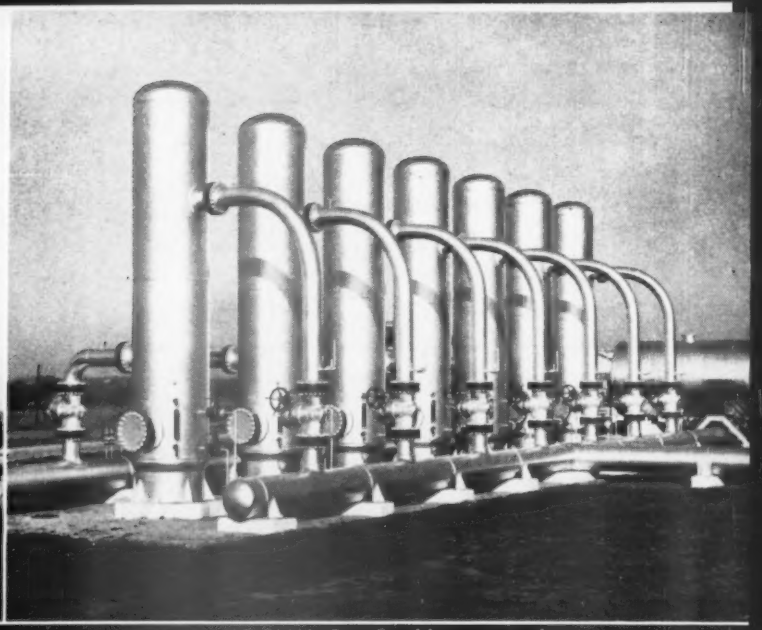
2. Hocott, C. R., and Buckley, A. E.: "Measurement of the Viscosity of Oils Under Reservoir Conditions," *Petr. Dev. and Tech.*, CSLII (1941).
3. Kimmel, M. L.: "The Development of a High Pressure Viscosimeter," a thesis submitted in partial fulfillment for the M.S. degree in Petroleum Engineering, Louisiana State University (1952), 52. ★★★



NATIONAL Gas Scrubbers, main line gas booster station, Batesville Miss.



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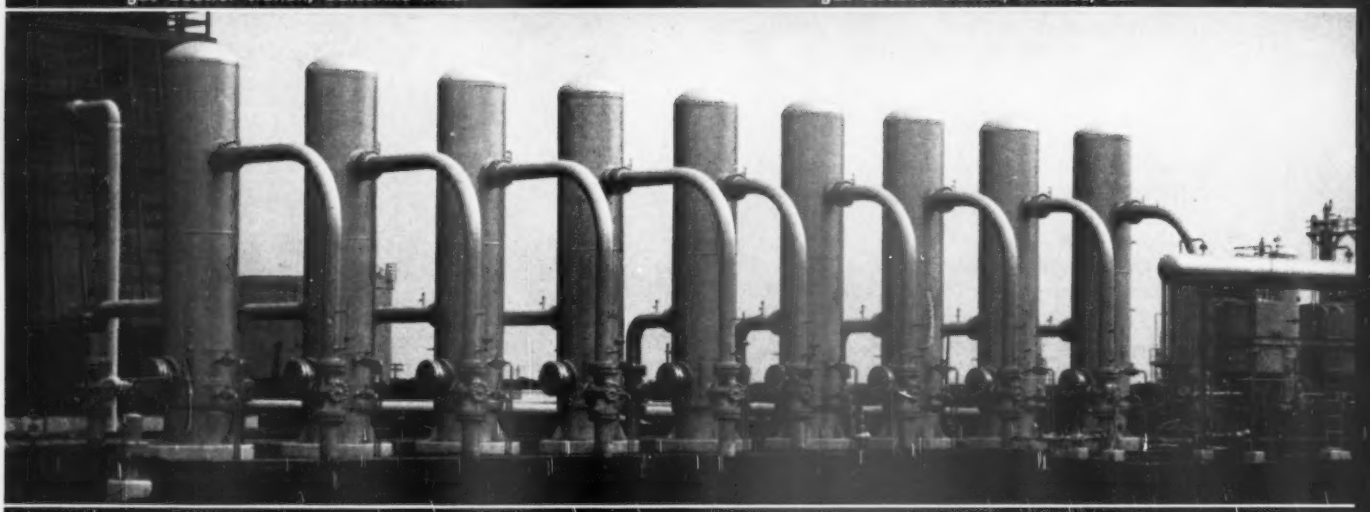

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PETROLEUM TRANSACTIONS

OPTIMUM SAND CONCENTRATIONS in WELL TREATMENTS

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T. P. 3929

ABSTRACT

Brief laboratory investigations are described which attempt to determine optimum sand concentrations in gel-sand and oil-sand[1] well-treatments. The investigations apply to the case where sand acts as a propping agent in formation fractures. Both analytically and experimentally it is demonstrated that optimum sand concentrations can be defined. It is difficult to translate laboratory results to field treatments, however, since the relative distribution of sand and fluid in fractures may not be the same as injected. This is because fluid may penetrate the furtherest narrow portions of fractures, which would not pass sand. Optimum concentration of a monolayer of Ottawa sand in fractures of 0.025-in. width at the usual range of pressures encountered in treatments appears to be about ½ to 2 lb/gal. of gel.

An investigation of abrasion of rock-walls by sand in treatments, described in the Appendix, shows that such abrasion is not probable in significant amounts.

INTRODUCTION

Experience in the Spraberry formation of West Texas, as well as in other formations, has shown that sand is a necessary and vital part of gel-sand and oil-sand treatments. Many observers of treatments have also concluded that there seems to be an optimum range of sand concentration for these injections. Brief laboratory investigations were made at Battelle Memorial Institute to study flow in fractures with different sand concentrations. To investigate the existence and range of optimum concentrations in the laboratory, however, necessitates knowledge of the mechanism by which the sand aids in increasing subsequent production.

The action of sand in fractures is usually thought to be either that of a propping agent, thus providing a greater effective formation permeability; that of an abrasive in eroding fill material in fractures; or that of an abrasive eroding rock-wall irregularities along fracture surfaces. Investigations described in the Appendix show that sand does not appear to erode rock-wall materials appreciably. In a subsequent paper it is reasoned, at least for the Spraberry formation of West Texas, that the primary action of sand is not in removing fill materials in fractures. In this formation, and probably others, too, the main effect of sand appears to be that of a propping agent.

Both analytical and experimental investigations were made for the case of a monolayer of sand acting as a propper, in which sand concentrations were determined that would, after treatment, permit flow of the maximum quantities of oil from the formation into a well. If too few sand grains are injected into fractures in which the bottom hole pressure has decreased appreciably below the original formation pressure, the confining pressure in the formation may become relatively large, thus compress the rock-walls around the sand grains, essentially close fractures, and so decrease the subsequent flow of oil. Similarly, if too much sand is used, the flow of oil will be impeded by the volume of sand present.

THEORY

Although an analytical approach to determining optimum sand concentrations involves gross assumptions,

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Manuscript received in Petroleum Branch offices on Apr. 1, 1954. Paper presented at Petroleum Branch Fall Meeting in San Antonio on Oct. 17-20, 1954.

[1]Reference given at end of paper.

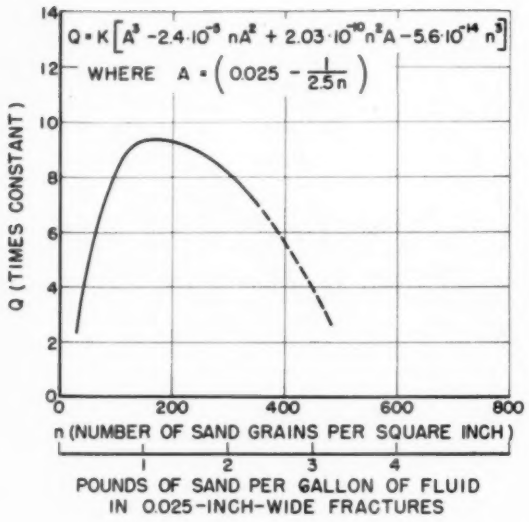
Q = K [A³ - 2.4·10⁻⁵ nA² + 2.03·10⁻¹⁰ n²A - 5.6·10⁻¹⁴ n³]
WHERE A = (0.025 - 1/2.5n)
Q (TIMES CONSTANT)
n (NUMBER OF SAND GRAINS PER SQUARE INCH)
POUNDS OF SAND PER GALLON OF FLUID IN 0.025-INCH-WIDE FRACTURES

FIG. 1 — CALCULATED RELATION BETWEEN FLOW RATE AND SAND CONCENTRATION FOR SPHERES 0.0025-IN. IN DIAMETER.

it may nevertheless indicate reasonable flow velocities for various sand concentrations. It is assumed for this analysis that sand particles are spherical in shape, uniform in size, the sand is distributed uniformly in fractures, and because of the greater hardness of the sand than that of nearly all formations encountered in treatments, the sand particles are, in effect, rigid. Most of the deformation encountered in a fracture would be expected to occur in the rock-wall contacting the sand. Consequently, as the confining pressure in a formation tends to close fractures around each sand grain, the area of contact between the rigid sand spheres and rock-wall increases.

The forces acting in a formation fracture are:

$$F_c = F_f + NF_s \quad \ldots\ldots\ldots \quad (1)$$

where F_c is the force, due to overlying rocks and regional stresses, tending to close fractures,
F_f is the force of formation fluid, tending to keep fractures open,
F_s is the force each sand grain exerts on the formation, tending to keep fractures open,
N is the number of sand grains.

In terms of pressures,

$$P_c - P_f = MF_s \quad \ldots\ldots\ldots \quad (2)$$

where P_c is the confining pressure in a formation, tending to close fractures,
P_f is the formation pressure,
M is the number of sand grains per sq in. of fracture surface.

Just prior to fracturing, F_s can be equated with the strength of the formation:

$$MF_s = anS_t$$

where a is the area of contact between sand grain and formation,
n is the minimum number of sand grains per sq in. of fracture surface required to prevent crushing in the wall-rock, and
S_t is the strength of the formation.

Equation (2) then becomes:

$$P_c - P_f = anS_t \quad \ldots\ldots\ldots \quad (3)$$

The area of contact of two portions of a spherical sand grain with the rock-wall, assuming the wall to be deformed around the sphere, is approximately:

$$a = 2\pi Dh = \pi D(D\text{-}W)$$

in the region where $W > \frac{D}{2}$, and

D is the diameter of sand grain,
W is the width of fracture, and

$$h = \frac{D\text{-}W}{2}$$

Equation (3) becomes:

$$P_c - P_f = \pi nD(D\text{-}W)\, S_t \quad \ldots\ldots \quad (4)$$

By assuming relevant values for a given formation and inserting them into Equation (4), n can be determined as a function of fracture width W. For the Spraberry formation, typical values at the bottom of a well may be approximately:

P_c = 2,500 psi (horizontal confining pressure)
P_f = 1,900 psi (bottom hole pressure)
S_t = 20,000 psi (strength of formation)
D = 0.025 in.

Then Equation (4) reduces to:

$$W = 0.025 - \left(\frac{1}{2.5n}\right) \quad \ldots\ldots \quad (5)$$

The relationship between flow rate and width between two parallel plates for laminar motion in the viscous range is[1]:

$$Q \sim W^3$$

where Q is the flow rate.

Sand between parallel plates decreases the volume open to flow by the volume of sand present, however. The flow is further complicated by the drag of fluid around each sand grain, although the extent of this drag is difficult to estimate. For low velocity flow in the viscous range, the drag will be small. If it can be assumed, to a rough approximation, that the flow rate varies directly as the volume available to flow between spheres in the fractures, then:

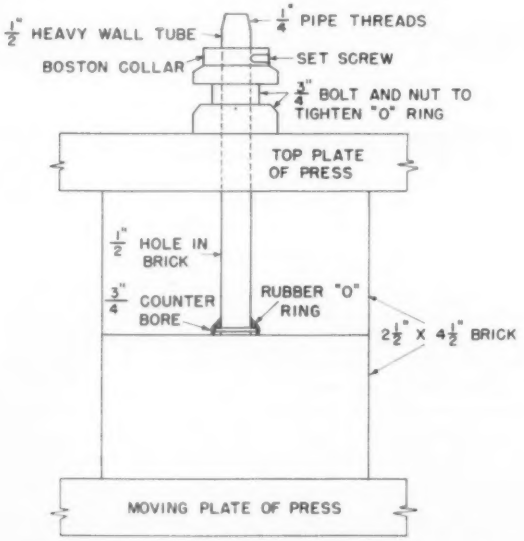

FIG. 2 — DIAGRAM OF CERAMIC-BRICK TESTING APPARATUS.

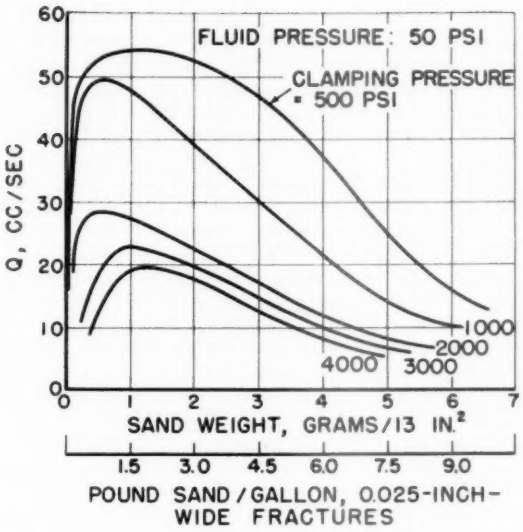

FIG. 3 — FLOW RATE OF SAE 10 MOTOR OIL AS FUNCTION OF SAND CONCENTRATION BETWEEN POROUS, SEMIHARD, CERAMIC BRICKS.

$$W_1 = W - n\left(\frac{\pi D^2}{6}\right) \quad . \quad . \quad . \quad . \quad . \quad . \quad . \quad (7)$$

where W_1 is the effective fracture width or the volume per sq in. of fracture surface open to flow.

Using this new effective fracture width in Equation (6), an equation in form:

$$\frac{Q}{K_1} = K_2 W_1^3 =$$

$$K_2\left(W^3 - \tfrac{1}{2}\pi n D^2 W^2 + 1/12\,(\pi^2 n^2 D^4 W) - \frac{1}{216}\,(\pi^3 n^3 D^6)\right) \quad . \quad . \quad . \quad . \quad . \quad . \quad . \quad . \quad . \quad . \quad (8)$$

is obtained,

where K_1 is a constant of proportionality, and
K_2 is a quantity indicating the effect of fluid drag.

For no drag, $K_2 = 1$; for drag, $K_2 < 1$.

Inserting Equation (5) into (8) gives, for conditions assumed in Equation (5), the equation shown and illustrated graphically on Fig. 1. Because of the assumptions involved, this equation is not reliable at the higher sand concentrations, although it appears more reasonable for the vicinity of the maximum of the curve.

Fig. 1 shows flow rate into a well as a function of the number of sand grains per unit fracture surface. The abscissa of this curve also shows sand concentrations in pounds per gallon of gel or oil for uniform fractures of 0.025 in. width. This curve may, in general, approach conditions near the bottom of a well in the Spraberry formation, where it would indicate minimum sand concentration before some crushing occurs in the wall-rocks.

The curve suggests that a maximum flow of oil may be anticipated in a well. For the assumed conditions, the maximum flow may be near 1¼ lbs of sand per gallon of fluid.

EXPERIMENTS

The test procedure was to place various monolayers of concentrations of sand between two ceramic bricks and determine fluid pressures required to obtain specific flow rates of SAE 10 motor oil along the interface between the bricks. Two different types of ceramic refractory bricks, both 3 x 4½ in. on a side, were used. The first set of bricks was quite impervious and hard. The second set was softer and more porous. In each test two bricks of the same type were clamped together between jaws of a hydraulic press, as illustrated in Fig. 2. A center hole through the top brick permitted injection of fluid to the interface between the bricks.

Sand weights of ⅛, ½, 1, 2, 4, and 6 gm were distributed evenly over the area of brick surface. Tests were made at specific flow rates of oil: 11, 18, 25, 37, and 50 cc/sec. The fluid injection pressures applied were those required to obtain the constant flow rates. In some instances these pressures ranged up to 10,000 psi, but they were generally lower. Pressures used to clamp the bricks together ranged from 500 to 4,000 psi and were varied at intervals of 500 psi.

Ottawa sand was used that passed a 20 but not 30 mesh screen. Thus, grains of reasonably uniform size, approximately 0.025-in. diameter, were used. In most tests the distribution of sand grains remained uniform during fluid injection. At higher sand concentrations there was some tendency for the injected fluid to redistribute the grains and open one or more channels, resulting in spurious flow rates. At lower sand concentrations, however, few channels formed so that the more reliable data were obtained at the lower concentrations.

Fluid pressures were obtained from a 150-ton capacity Watson-Stillman Press which has a maximum ram velocity of 1½ in./sec. Clamping pressures on the interface containing sand were obtained with a 2-ton hydraulic jack. Because it was easier to vary pressures

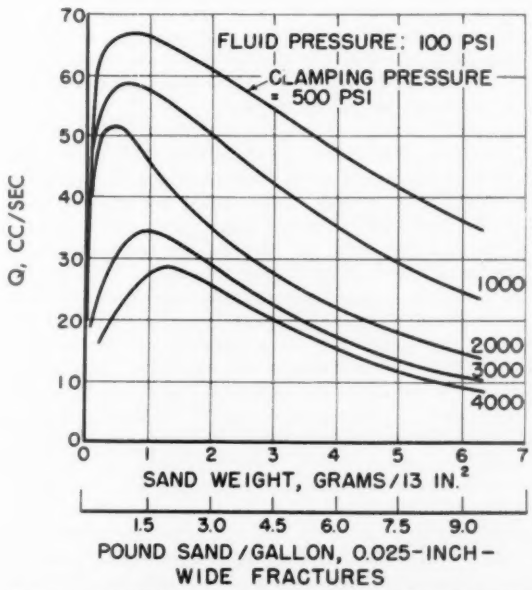

FIG. 4 — FLOW RATE OF SAE 10 MOTOR OIL AS FUNCTION OF SAND CONCENTRATION BETWEEN POROUS, SEMIHARD, CERAMIC BRICKS.

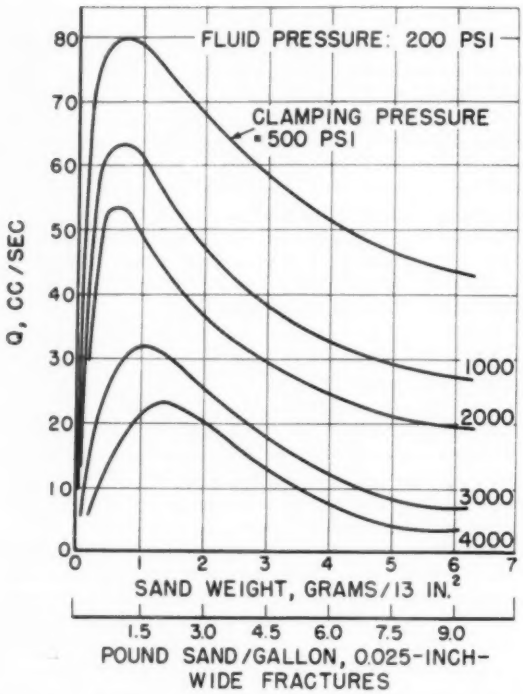

FIG. 5 — FLOW RATE OF SAE 10 MOTOR OIL AS FUNCTION OF SAND CONCENTRATION BETWEEN POROUS, SEMIHARD, CERAMIC BRICKS.

rather than flow velocities with this equipment, basic measurements were made by recording injection pressures as functions of clamping loads for specific sand concentrations and flow rates. Curves of the basic data were cross-plotted to show fluid pressure as a function of sand concentrations for specific flow rates and clamping pressures. Neither of these sets of basic curves is presented in this paper. Figs. 3 through 6 are further cross-plots, showing the desired flow rates as functions of sand concentration for specific injection and clamping pressures in the softer bricks.

Figs. 3 through 6 indicate that there are sand concentrations that permit a maximum flow of oil and that this maximum varies with clamping pressure and, possibly, fluid pressure. Very similar curves, with maxima shifted slightly toward larger sand concentrations, were obtained with the harder, less porous, bricks. The hardness of a formation thus has a minor effect on optimum sand concentrations: the harder formations would require slightly larger amounts of sand to permit maximum flow at comparable pressures. It is noteworthy that the general shapes of the experimental curves are similar to the analytical one shown on Fig. 1, although the experimental results indicate somewhat lower optimum concentrations. Whereas optimum concentrations for 0.025-in. wide fractures and specified pressures were calculated to be about 1¼ lbs/gal. of fluid, the laboratory results indicate optimum concentrations closer to ½ or 1 lb/gal. for comparable pressures. A significant difference between these curves is that the sand content in Fig. 1 refers to the minimum amount necessary to prevent crushing in fractures, whereas in Figs. 3 through 6 the concentrations may be both greater and less than this amount.

Fig. 7 shows maximum flow rates of SAE 10 oil, as obtained from the maxima of Figs. 3 through 6 and similar curves (not shown) for the harder bricks, for various clamping pressures as functions of sand concentration. Within the experimental error, these curves appear to be independent of flow pressure. Magnitudes of maxima flow rates were found to be about the same in both the harder and softer bricks for comparable pressures. However, the maxima were shifted toward higher sand concentrations in the harder bricks, as indicated in Fig. 7.

In correlating these laboratory data with field conditions, fluid pressures in the laboratory correspond approximately to the difference in formation and bottom hole pressures, and clamping pressures to the pressure tending to close the formation fractures (see section on "Theory"). In most formations encountered, these pressures would correspond to laboratory injection pressures up to about 1,000 psi and clamping pressures up to about 3,000 psi, or more in some instances. In the Spraberry formation, applicable fluid pressures would probably be less than 600 psi and clamping pressures well below 1,000 psi.

Although tests with bricks suggest that for specific pressure conditions optimum sand concentrations can be determined in fractures of formations of given hardness, care must be exercised in translating these laboratory results to field conditions. To apply laboratory results directly to concentrations injected implies that all sand travels as far in fractures as does the fluid and remains mixed in a constant ratio with the fluid. Unfortunately, little information is available on the relative penetrability of sand with respect to fluid.

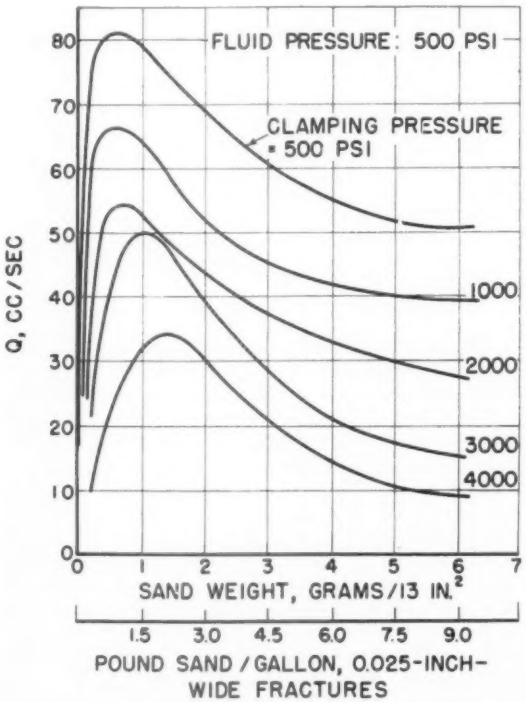

FIG. 6 — FLOW RATE OF SAE 10 MOTOR OIL AS FUNCTION OF SAND CONCENTRATION BETWEEN POROUS, SEMIHARD, CERAMIC BRICKS.

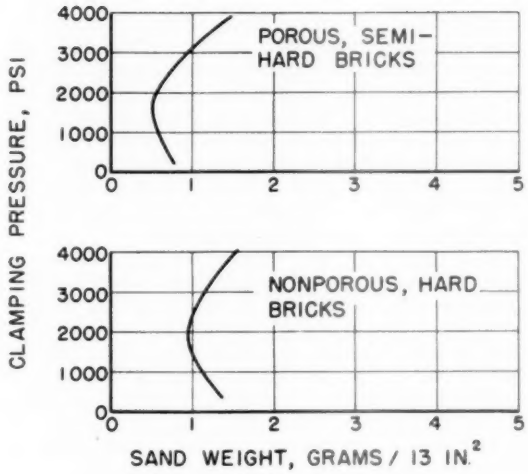

FIG. 7 — TYPICAL CURVES OF MAXIMUM FLOW RATE OF SAE 10 MOTOR OIL, FOR DIFFERENT CLAMPING PRESSURES AND SAND CONCENTRATIONS, WITH TWO DIFFERENT TYPES OF CERAMIC BRICKS.

However, as the fluid probably travels further than sand in narrow fractures, actual concentrations in fractures will probably be greater near the well than in the injected mixture.

Figs. 3 through 6 indicate that flow velocity is not particularly sensitive to sand concentration. Thus, although concentration for effective flow should not be less than a certain minimum, optimum concentrations can be exceeded appreciably without a significant reduction in flow. As there may be a tendency for the formation to creep, i.e., to close fractures long after the sand has been injected, it would seem advisable to use more than the apparent optimum concentration.

CONCLUSIONS

It is concluded that optimum sand concentrations do exist for treatments of fractured formations where the sand acts as a propping agent, and that this optimum does not seem to be very sensitive. For Ottawa sand this apparent optimum concentration, in fractures 0.025-in. wide, may be between ½ and 2 lbs/gal. of fluid. Effective optimum concentrations in treatments, allowing for creep in the fractures in the course of time, may be somewhat greater. The optimum concentration is a function of the formation pressure, bottom hole pressure, hardness of formation, formation confining pressure, and viscosity of oil.

In converting laboratory sand concentrations to field application, the relative penetration of fractures by sand and fluid as the fracture width narrows must be estimated. Where desirable sand concentrations in fractures can be inferred, effective injection concentrations might be estimated to obtain such mixtures in fractures. For example, if the desired amount of sand in fractures, allowing for a moderate excess is 2 lbs/gal. and if the sand is assumed to spread over only half the volume occupied by fluid, then the proper injected mixture might be 1 lb/gal.

APPENDIX

Since the possibility of sand eroding rock-walls in well treatments has been raised on occasions, a number of qualitative laboratory tests were made at Battelle to determine the likelihood of this action. Initial tests for abrasion were made on fractured surfaces of Spraberry cores. Similar tests were made with relatively soft transparent Lucite discs.

TEST PROCEDURE

The same press was used as in the tests with ceramic bricks. A fractured Spraberry core, usually 3½ in. in diameter, was clamped between plates of the press (Fig. 8) by a 20-ton hydraulic jack. In contrast to the previously described tests, a gel-sand was injected in the abrasion tests. The gel-sand consisted of 85 gm of aluminum soap and ¼ lb of sand/gal. of kerosene. This fluid was injected into the fracture surface at specific pressures through a hole in the top half of the core. The flow rate of the fluid ejected from the fracture surface was measured. This fluid was injected at various pressures, some at high enough pressures to rupture the cores. Generally, injection pressures were sufficiently lower than clamping loads to permit injection and flow of sand and gel through the original core fracture. A fairly rounded lake sand was used which had an average diameter of 0.018 in. Sand was injected uniformly over the interface in these tests, but careful examinations of the rock surfaces indicated that the sand did not erode any of the rock materials significantly.

A number of similar tests were made with Lucite discs to determine whether the softer material could be abraded more readily. In the tests it was also attempted to evaluate abrasion both parallel and perpendicular to the direction of flow. In one set of tests, two flat Lucite discs, 1 in. thick and 4 in. in diameter, were used (as shown in Fig. 9, except that the interface between the discs is flat). They were placed in the same apparatus used for the rock cores and ceramic

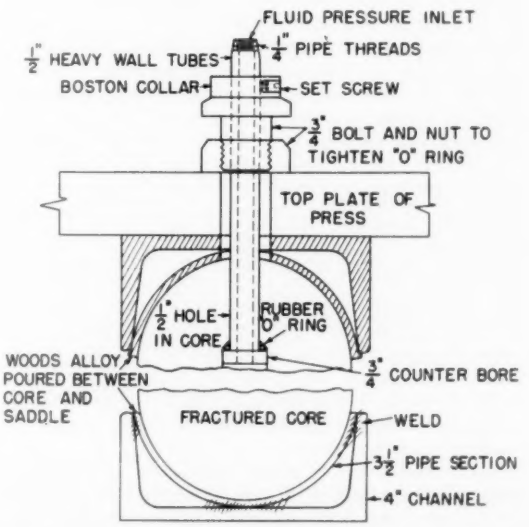

FIG. 8 — DIAGRAM OF FRACTURED-CORE TESTING APPARATUS.

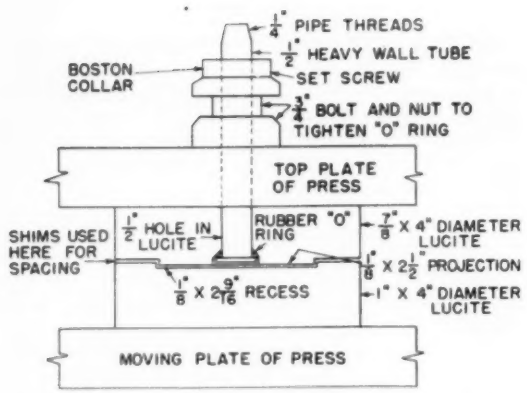
1/4" PIPE THREADS
1/2" HEAVY WALL TUBE
BOSTON COLLAR
SET SCREW
3/4" BOLT AND NUT TO TIGHTEN "O" RING
TOP PLATE OF PRESS
SHIMS USED HERE FOR SPACING
1/2" HOLE IN LUCITE
RUBBER "O" RING
7/8" X 4" DIAMETER LUCITE
1/8" X 2 1/2" PROJECTION
1/8" X 2 9/16" RECESS
1" X 4" DIAMETER LUCITE
MOVING PLATE OF PRESS

FIG. 9 — DIAGRAM OF RECESSED LUCITE-DISK TESTING APPARATUS.

bricks. In other tests, Lucite discs with a cylindrical recess (Fig. 9) were used to evaluate abrasion in different flow directions.

The Lucite discs were separated by three shim spacers of various thicknesses, located radially at 120°. The spacer thickness was varied, with different discs used for each set of spacers, from 0.010 to 0.033 in. Clamping pressures exceeded fluid pressures in these tests so that the spacers would not be removed during injection, yet this pressure difference was not so large as to cause indentations on the discs. Fluid pressures ranged up to 400 psi, the maximum available with this testing arrangement.

TEST RESULTS

Since Spraberry cores were not abraded appreciably, most of the results pertain to Lucite. When spacers of 0.017 in. or less were used, sand was filtered at the inlet hole of the top disc, but was not injected into the interface between the discs; only gel was ejected from the disc interface then. When spacers of 0.018 in. and larger were used, sand and gel were ejected from the interface between the discs. When a low injection velocity was applied, corresponding to a pressure of 30 psi, the discs were not abraded. At a fluid pressure of 400 psi varying degrees of abrasions were observed on the lower disc. Abrasion was greatest with the 0.018-in. spacers, the diameter of the sand grains, and was progressively less as the spacing was increased. At the higher injection pressures a deep erosion pit was created in the lower disc just around the region of the inlet recess. For the 0.018-in. spacer this pit was found to extend over approximately 90° and was about 1/32-in. deep and ⅛-in. long. Less pronounced erosion pits were observed for larger shim spacers. With 0.025-in. spacers, the pit was barely noticeable. Beyond the abraded pit, sand produced radial scratches when spacers were 0.018 or 0.019-in. thick. When larger spacers were used, such abrasion marks were not observed.

Lucite discs with a recess were used to investigate erosion as a function of flow direction. The injected fluid made two right angle turns between the discs before extrusion. The upper disc mates the lower one except for a 1/32-in. clearance on the projected parts of the cups (Fig. 9). Three 1/32-in. diameter pins were placed at the edges of the recess at 120° to provide equal circumferencial spacing of the discs. Although abrasion was pronounced toward the center of the lower disc when an 0.018-in. spacer was used at a fluid pressure of 200 psi, only slight abrasion was observed near the outer edge of the lower disc. No abrasion was observed along the vertical walls of the recess, presumably because the spacing there was greater than the sand grain diameter. Larger shim spacers resulted in even less abrasion.

Since abrasion was found to be most pronounced when the fracture width was approximately equal to the sand grain diameter, the discs in Fig. 9 were modified in further tests. The three pins were removed and the upper disc was placed in contact with one end of the recess of the lower disc, so that spacing between the recesses varied from 0 to 1/16-in. When 0.018-in. shims were used, nearly all the gel-sand was ejected from the wider side of the recess, so that no abrasion was observed along the vertical portion of the recess. Time did not permit further modification of these test procedures.

CONCLUSIONS FROM ABRASION TESTS

The brief investigations with the Spraberry cores and the Lucite discs have indicated that:

1. No evidence for abrasion was observed on fracture surfaces of Spraberry cores. Greater sand concentrations could have resulted in some abrasion, but probably not in significant amounts.

2. Abrasion of Lucite by sand in gel is significant only when the spacing between the discs is nearly equal to the sand grain diameter. Too small a spacing results in filling the inlet area with sand, passing only fluid between the discs, while too large a spacing allows the sand to pass between films of fluid without scratching the surfaces.

3. Maximum abrasion also appears to require a high flow velocity and normal incidence of sand striking a surface; i.e., where the sand has a blasting effect. Greater sand concentrations would probably also result in some increased abrasion.

Translating these laboratory results to application in the field indicates that:

1. Except in the softest and least consolidated formations, abrasion of wall rock by sand in treatments appears to be of minor importance. In those portions of formation fractures where widths equal the sand grain diameter there might be some local abrasion.

2. Where fracture widths are less than the sand grain diameters, it appears that sand would plug the inlet to the fracture. This means that fractures will have to be widened to at least the sand grain diameter before an injection with sand is possible.

ACKNOWLEDGMENTS

Permission by The Western Co. to publish these results is gratefully acknowledged. Members of a Steering Committee at the Battelle Memorial Institute, formed to guide this and similar investigations, have provided valuable and significant suggestions.

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★★★

MEASUREMENT of RESISTANCE to FLOW of FLUIDS in NATURAL GAS WELLS

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R. H. WILLIAMS**
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T. P. 3928

ABSTRACT

Before this paper was presented, the terms "f" and "$\sqrt{1/f}$" in flow equations had been called "friction coefficient" and "friction factor," respectively. However, many authors have used the names for the terms interchangeably, with the result that considerable confusion has existed in the literature on flow of fluids. In an effort to establish a clear and concise terminology for these terms, the authors have designated f as "resistance coefficient" and $\sqrt{1/f}$ as "transmission factor."

Transmission factors for the flow strings of gas wells were determined by tests on wells in six fields of Oklahoma, Texas, and Louisiana. Data were collected on 14 gas wells while gas was flowing through 1¼, 2, 2½, and 3-in. tubing and 5½ and 7-in. casing. The transmission factors developed from these data were found to follow the resistance equation published by Nikuradse[1] for turbulent flow in "rough" pipes with an average absolute roughness of 0.000,65 in. This average absolute roughness is believed to be representative generally of the flow strings of gas wells with the exception of those that have been exposed to corrosion or other conditions causing undue roughness. Also, use of an absolute roughness of 0.000,65 in. probably will result in transmission factors that are more representative of gas-well conditions than those in common use today, provided that the transmission factors are calculated by the methods outlined in this report. The authors believe that use of these transmission factors will permit calculation of more accurate subsurface pressures in gas wells than those in use today.

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Paper received in Petroleum Branch offices on Apr. 28, 1954.
[1]References are given at the end of the paper.

INTRODUCTION

Engineers use transmission factors in flow equations to compute subsurface pressures in flowing gas wells from measured wellhead pressures. These subsurface pressures are necessary for determining the productivity of gas wells from "back-pressure" tests. The methods of calculating pressures in flowing gas wells, as outlined by Rawlins and Schellhardt[2] in *Bureau of Mines Monograph 7*, are based on the transmission factors in the well-known Weymouth formula[3]. Natural gas engineers have realized that errors introduced by using transmission factors as given by the Weymouth formula are relatively unimportant in testing low-capacity gas wells; but they also know that such factors are important considerations in testing large-capacity wells. Accordingly, the research described in this report was undertaken to fulfill the need for more accurate means of calculating subsurface pressures in gas wells.

This report is part of the Bureau's study of the flow of natural gas through pipe and commercial pipelines. Several of the conclusions regarding flow in the flow strings of gas wells were influenced by the results of the study of flow in horizontal pipelines. These instances are mentioned in the text of this report.

METHODS OF COMPUTING TRANSMISSION FACTORS

Methods and procedures for computing transmission factors for turbulent flow in circular pipes from test data taken on gas wells have been derived and explained in detail in a paper by Smith[4]. As these methods were used to calculate the transmission factors presented in this report, a summary is included. Starting with

an energy balance over a differential length of pipe and defining the resistance coefficient, f, by the equation:

$$\text{frictional resistance} = dF = \frac{4fU^2dL}{2gD} \quad . \quad . \quad . \quad (1)$$

The following vertical-flow equation was derived by integration of the energy balance over the length of pipe considered:

$$144\int_{P_w}^{P_s} vdP = L_s + \frac{Q^2G^2(V_w^2 - V_s^2)}{2.551,5 \times 10^8 d^4} + \frac{fQ^2G^2}{53.157 \times 10^8 d^5}\int_0^L v^2dL \quad . \quad . \quad . \quad . \quad . \quad . \quad (2)$$

The subscripts s and w refer to conditions at depth L and at the wellhead, respectively. Line integral signs were used because the values of specific volume required for the integration are a function of the temperature and compressibility as well as of the pressure and the relation between temperature and pressure is not specified by the terms of the integral.

As Equation (2) does not contain assumptions that define the path of the flow process of the fluid, it is considered general for the flow of fluids in wells.

The authors have found that Equation (2)* was particularly useful and reliable in evaluating the resistance coefficient, f, for gas wells. Pressures and temperatures must be measured in the flowing column of gas at enough depths in the well to permit accurate evaluation of the two integrals in Equation (2). As the flow mechanism in a well is essentially a weight-lifting process with frictional effects, the specific-gravity term G must convert the volume of gas into the weight of the total fluid lifted in the flow. Consequently, the specific-gravity term must be representative of the hydrocarbon liquid and gases produced during the flow. If the well produces water as a result of the condensation of water vapor that entered the well from the reservoir, a separate energy balance can be approximated for the water whereby the deficiency in energy supplied by the water toward lifting itself can be subtracted from the available energy of the gas. However, the effect of water condensed from vapor was found to be small, probably being less than the experimental errors in determining transmission factors for gas wells.

The application of Equation (2) to test data on gas wells measured with subsurface instruments requires a high degree of pressure and flow-rate stabilization of the reservoir surrounding the well. Measurement of pressures and temperatures at several depths in the well simultaneously is impossible with existing equipment and changes in pressures or flow rate before measurements at all depths have been completed will result in errors in the application of Equation (2) to flow test data.

To develop an equation similar to those commonly used in problems of flow in horizontal pipelines, Smith[1] integrated the energy balance equation for a finite length of pipe with an "effective" compressibility factor and an "effective" temperature to arrive at the following equation:

$$Q = 19,686\frac{(1)}{(ZT)}\sqrt{\frac{1}{f}}\sqrt{d^5\left(\frac{P_s^2 - e^sP_w^2}{e^s - 1}\right)} \quad . \quad (3)$$

Equation (3) is based on the assumptions that the temperature in a well is constant at an "effective" value, that the change in kinetic energy is negligible, and that the compressibility of the fluid in the well can be approximated by a constant "effective" value. The latter assumption is equivalent to assuming that the ideal-gas laws hold for the gas in a well but with a different value assigned to the gas constant in the ideal-gas equation. The accuracy of Equation (3) for determining transmission factors is limited because average effective compressibilities and temperatures must be estimated. However, subsurface pressure and temperature gages could not be run through the 1¼-in. tubing and against several of the higher flow rates in 2, 2½, and 3-in. tubing to provide data for Equation (2). In these instances, Equation (3) was used to compute transmission factors. Flow tests, when possible, were conducted to meet the requirements of Equation (2) because it will provide transmission factors of greater accuracy than Equation (3).

Exact methods of estimating the average effective compressibilities and temperatures for use in Equation (3) to describe adequately the behavior of a column of flowing gas are not known. However, reasonably accurate estimates of these factors can be made from prior knowledge of well behavior or the behavior of similar wells. Usually, the average effective temperature is an arithmetic average of the wellhead temperature and the subsurface temperature at the desired depth, providing temperature is a straight-line function of depth. Otherwise, an integrated average is used. The average effective compressibility is taken at the effective temperature and the estimated average pressure.

All transmission factors given in this report are based on pressure measurements between a depth of 50 ft and lower depths in the flow string. This was done to eliminate the effects of wellhead fittings on the resulting transmission factors.

REYNOLDS NUMBERS FOR FLOW IN GAS WELLS

The Reynolds number, a dimensionless ratio commonly used to characterize the conditions of fluid flow in circular pipes, is given in the literature as:

$$R = \frac{DUS}{\mu}$$

The above relationship has been expressed by Biddison[2] in natural gas engineering terms as:

$$R = 13.23 \times 10^6\frac{QG}{\mu d} \quad . \quad . \quad . \quad . \quad . \quad (4)$$

The viscosity of the fluid in a flowing gas well varies from the bottom of the well to the top because of the change in viscosity with pressure and temperature. Consequently, the Reynolds number varies also, although in most flowing gas wells the variation is small. In this paper, all Reynolds numbers were computed by means of Equation (4) for the midpoint of the pipe under consideration to provide a standard basis for comparison. Values of the viscosities of the gases were taken from charts published by Bicher and Katz[6] and converted to the proper units for use in Equation (4).

*Equation (2) states that the available energy from the flow process equals the energy required to lift the fluid plus the energy involved in the kinetic energy change plus the energy required to overcome friction. The maximum observed energy involved in the kinetic change for all of the wells studied was 0.2 per cent of the total available energy. Consequently, the kinetic energy term in flow equations for gas wells can be neglected for all practical purposes.

EXPERIMENTAL PROCEDURE

After a well had been selected for testing, it was started producing at a flow rate high enough to cause a pressure drop along the flow string that would provide pressure data for accurate determinations of transmission factors. The lowest flow rates practicable for transmission-factor determinations varied from 2 MMcf/24 hours in 2-in. tubing to about 7 MMcf/24 hours in 7-in. casing. After the desired flow rate had been obtained, the rate of gas production was measured with an orifice meter and calculated for 20-minute intervals. The specific gravity of the produced gas was measured at each test flow rate. If the well produced hydrocarbon liquid and water, the rate of production was determined by measuring the accumulation of liquid in the separator over a particular time interval. Liquid water was measured by draining the water from the separator into a calibrated container at regular intervals of time depending upon the rate of water accumulation. Simultaneously with the rate measurements, the wellhead pressures, both tubinghead and casinghead, were measured by means of a piston gage at regular intervals of, usually, not longer than 20 minutes.

After both wellhead pressure measurements and rate determinations indicated that a satisfactory stable flow had been reached, pressures and temperatures at depths ranging from 50 ft below the wellhead to within 50 ft of the bottom of the flow string were measured with subsurface pressure and temperature gages. The flow rate against which the subsurface gages could be run was severely limited in tubing by two factors. First, the presence of the gages in the flow stream would decrease the flow rate to a slight degree depending principally upon the flow rate. Second, at the higher rates of flow, the gas stream would lift the gages in the tubing. After the subsurface pressures and temperatures were measured, the producing rate of the well was changed and the experimental procedure repeated.

Selection of Test Wells

Test wells were selected primarily to obtain transmission factors for flow strings in common use in gas wells. Although 1¼-in. tubing is not commonly used for flow strings in gas wells, this size tubing was included in the study because it is used to remove liquids from gas wells. Flow strings of casing alone, without tubing, are in general use in the Panhandle gas field of Texas.

Wells selected for testing in the study of transmission factors had to meet several important requirements regarding equipment, condition of the flow string, and the production of formation water. The required wellhead equipment included suitable connections for the measurement of pressures and, except in the case of the 1¼-in. tubing, "full opening" wellhead valves so that subsurface-pressure and temperature gages could be lowered into the well. Flow strings coated with drilling mud or mud from the producing formation would be unsuitable for the determination of transmission factors. A coating of mud or cement would not only decrease the pipe diameter but would also change materially the roughness of the internal surface. Flow strings that have been subjected to corrosion have roughness characteristics that are unusual and, for this reason, should not be included in a summary of transmission factors for normal gas wells.

The presence of liquid formation water in the flowing gas causes pressure losses other than that involved in the passage of the gas past the pipe surface. However, a certain amount of water is condensed from the water vapor contained in the reservoir gas (reservoir gas is in equilibrium with the connate water of the reservoir) as the gas flows up the flow string of a well, so the presence of some water in the flow string of a gas well cannot be avoided. No well was selected for test that produced salt water, as the liquid water complicates the determination of transmission factors.

Flow and Pressure Stabilization

Although transmission factors may be determined for the flow strings of wells that stabilize slowly, such tests are unduly time consuming. Equation (2) requires a constant value for the rate of flow in addition to constant wellhead and subsurface pressures. As subsurface pressures at successive depths in the well could not be measured simultaneously, a constant flow rate was required for the period of time necessary for the pressure measurements. However, the ideal conditions outlined above are seldom if ever attained in gas-well testing; as a result, the procedure followed was a compromise between ideal conditions and a degree of stabilization that could be reached in a reasonable time. When possible, the test well was maintained at the desired rate of production overnight before the transmission-factor data were taken. Normally, changes in flow rate during testing were small; after a major change in rate, the well under test was allowed to flow 12 to 16 hours. Usually the stabilization of a well was considered to be satisfactory when any change in wellhead pressure was within 0.1 to 0.3 psi in a 20-minute interval and at the same time there was no observable change in the flow rate, as indicated by the orifice meter.

Measurement of Subsurface Pressures and Temperatures

In measuring subsurface pressures and temperatures, a pressure gage and a temperature gage were run in the well as a unit. No pressure measurements were made without a corresponding temperature measurement. The gages were run first to a depth of 50 ft in the well and allowed to remain there until complete temperature equilibrium was reached. Then the gages were lowered to successive depths in the flow string. Pressures and temperatures were measured at eight depths in wells with about 3,000 ft of flow string and at 10 or 11 depths in wells with longer flow strings. The lowest depth at which measurements were taken was 50 to 100 ft above the highest opening in the flow string. At each "stop" or depth, the wellhead pressures (both tubing and casing) were measured to 0.1 psi with a calibrated piston gage.

The pressure and temperature deflections of the gages were recorded on polished-aluminum foil charts with Permopivot phonograph needles that made lines less than 0.001 in. in width. Deflections on the charts were measured to 0.001 in. and estimated to 0.000,1 in. with a comparator microscope and converted to corresponding pressures and temperatures by the methods published by Smith and Dewees[2] and Smith, Dewees, and Williams[3].

In addition to the techniques described above, the accuracy of the pressure gages in field usage was de-

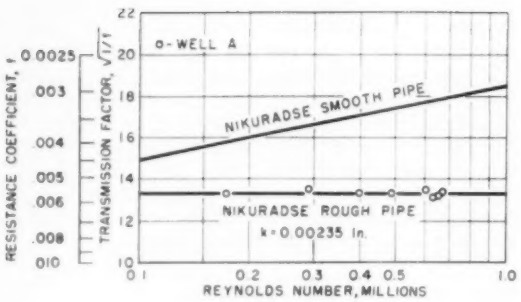

FIG. 1 — EXPERIMENTAL TRANSMISSION FACTORS DETERMINED FOR 1¼-IN. TUBING (ID—1.380 IN.); PANHANDLE FIELD, MOORE COUNTY, TEX.

termined after each series of transmission-factor determinations by shutting in the well and measuring pressures in the shut-in column of gas. These measured pressures were subsequently compared with pressures computed for the same depths by the method published by Rzasa and Katz[9]. In the dry-gas wells in the Panhandle field, Tex., where reservoir pressures varied from 270 to 380 psia, the difference between calculated and measured subsurface pressures averaged 0.25 psi for 19 determinations. The corresponding difference for wells in a Louisiana field averaged 1.3 psi for 10 determinations for pressures ranging from 1,500 to 1,600 psia. This comparison method of determining gage accuracy in these wells that produced appreciable quantities of hydrocarbon liquids gave differences that could be explained only by errors in the method of computing pressures.

Transmission factors reported for the 1¼-in. tubing and at several flow rates through the 2, 2½, and 3-in. tubing where it was impossible to run subsurface gages were computed with Equation (3), the integrated equation. In these cases, the subsurface pressures at the lower end of the tubing were calculated from wellhead pressure measurements on the static column of gas in the annular space between the tubing and casing by a modification of the method of Rzasa and Katz[9].

GAS MEASUREMENT

The rate of gas production was measured with standard orifice meters and computed to a pressure base of 14.4 psia and 60° F in accordance with *Gas Measurement Committee Report No. 2*, issued by the American Gas Association, with a correction of volume for the compressibility of the gas at meter conditions. The static element of the orifice meter was calibrated with a piston gage, and the differential element was compared with a water manometer at several differential pressures over the range of the orifice meter. Calibration corrections were applied to the static and differential pressures in the flow computations. Orifice-meter readings and observations of the temperature of the gas flowing through the meter were taken at 20-minute intervals after stabilization of well pressures, and the resulting flow rates were averaged for calculating transmission factors. The specific gravity of the gas was measured with a gas-gravity balance several times during each test period.

RESULTS OF TESTS TO DETERMINE TRANSMISSION FACTORS

Tests to determine transmission factors for the flow of natural gas in circular flow strings in wells were completed for 1¼, 2, 2½, and 3-in. tubing and 5½ and 7-in. casing. The resulting transmission factors, with corresponding Reynolds numbers are illustrated in Figs. 1 to 6, inclusive. In addition, the Nikuradse[10] resistance equation for turbulent flow in smooth pipes is shown by a diagonal line in each figure. This equation is:

$$\sqrt{1/f} = 4 \log R\sqrt{f} - 0.4 \quad . \quad . \quad . \quad . \quad . \quad (5)$$

Although Equation (5) appears to be a straight line on the semilogarithmic coordinates of Figs. 1 to 7, the line actually is slightly curved. The Nikuradse smooth-pipe curve, Equation (5), is shown on the illustrations, because many investigators in the field of fluid mechanics believe that the Nikuradse resistance equation for flow in smooth pipes represents the highest value of the transmission factor at a given Reynolds number for any type of pipe surface. The line at a constant value of the transmission factor drawn through the developed data points represents the Nikuradse resistance equation[7] for turbulent flow in *rough pipes*, which is

$$\sqrt{1/f} = 4 \log \left(\frac{7.4r}{k} \right) . \quad . \quad . \quad . \quad . \quad . \quad (6)$$

The relative roughness used to determine the position of the line was the average of the absolute roughness value for each datum point divided by the pipe radius and was calculated by Equation (6). In Nikuradse's experimental work the absolute roughness was considered to be the diameter of the uniform sand grains glued to the test-pipe interior. By using various sizes of uniform sand, Nikuradse measured transmission factors for a 30-fold variation in the ratio of sand-grain diameter to pipe radius. These experiments enabled Nikuradse to arrive at Equation (6) for turbulent flow in rough pipe. Equation (6) is significant in that it does not contain the Reynolds number, which means that the fluid viscosity has no influence on the flow or the transmission factor.

TRANSMISSION FACTORS FOR 1¼-IN. TUBING

The transmission factors illustrated in Fig. 1 were determined for a string of 1¼-in. tubing (2.4 lb/ft, EUE) that had been installed in a gas well in the Panhandle field in Moore County, Tex. As mentioned previously, although 1¼-in. tubing is seldom used as a flow string in gas wells, these transmission factors are included in this report because 1¼-in. tubing is used widely as "siphon strings" to remove water from gas wells. However, this particular well did not produce water, and the tubing had not been used for gas or water production. This circumstance may have resulted in an abnormal pipe-surface condition with the resultant unusually high absolute roughness measurement for the tubing shown in Table 1.

As illustrated in Fig. 1, the transmission factors were relatively constant and independent of Reynolds number over the entire range of data from 173,000 to 671,000 and can be represented closely by the Nikuradse equation for flow in rough pipe with an average relative roughness of 0.003,40. The corresponding aver-

TABLE 1 — SUMMARY OF RELATIVE AND ABSOLUTE ROUGHNESS VALUES FOR GAS-WELL FLOW STRINGS COMPUTED BY THE NIKURADSE ROUGH-PIPE EQUATION

Pipe size, in.	Internal diameter, in.	Wells included	Relative roughness, k/r	Absolute roughness, k, in.
1¼-in. tubing	1.380	A	0.003,40	0.002,35*
2-in. tubing	1.995	B, C	.000,534	.000,532
2½-in. tubing	2.441	D, E, F	.000,530	.000,647
3-in. tubing	2.992	G, H	.000,565	.000,846
3-in. tubing	2.992	I	.006,12	.009,15*
5½-in. casing	5.012	J, K, L	.000,292	.000,732
7-in. casing	6.336	M	.000,103	.000,325
7-in. casing	6.398	N	.000,260	.000,831

*Excluded from average. Average = 0.000,65 in.

age absolute roughness is 0.002,35 in. The relatively small diameter of the 1¼-in. tubing prevented the measurement of pressures and temperatures in the tubing with subsurface gages. Consequently, data were taken and calculated by the methods explained in the discussion of Equation (3).

Transmission Factors for 2-in. Tubing

The transmission factors determined for the 2-in. tubing (4.7 lb/ft, EUE) of two gas wells in Leon County, Tex., are illustrated in Fig. 2. These wells produced hydrocarbon liquid that varied from 1.4 to 6.8 bbl/MMcf of separator gas. Usually, the higher hydrocarbon liquid-gas ratios were observed at the lower flow rates. These wells produced, with the hydrocarbon liquid, relatively small quantities of fresh water which probably entered the wellbore in the vapor state. Neither the past history of the wells nor inspection of well equipment at the time of testing gave any indication that the well equipment had been subject to corrosion.

The transmission factors for 2-in. tubing, illustrated in Fig. 2, were constant and independent of Reynolds number or fluid viscosity over the experimental range of Reynolds numbers from 0.567 to 4.48 million. The straight line through these transmission factors is the Nikuradse rough-pipe equation for a relative roughness of 0.000,534 or an absolute roughness of 0.000,532 in. The accuracy of the data as indicated by the spread of points about the line is probably within the range of experimental error. The first two points for each well in Fig. 2 are the averages of data developed from five successive measurements of pressures with subsurface gages at depths of 300-ft intervals. (Actual depths were 4,000, 4,700, 5,000, 5,300, and 5,600 ft). The first two transmission factors for each well were calculated by Equation (2), the line-integral method. The remaining data were calculated by means of Equation (3) from surface measurement of pressures. The measurement of pressures and temperatures in 2-in. tubing with subsurface gages at flow rates greater than 3.5 MMcf/24 hours was considered to be unsafe, as determined from previous experience.

Transmission Factors for 2½-in. Tubing

The transmission factors determined for the 2½-in. tubing (6.50 lb/ft, EUE) of three gas wells are given in Fig. 3. Wells D and E were in Bossier Parish, La., and Well F was in Caddo County, Okla. Wells D and E produced small quantities of fresh water and hydrocarbon liquid that varied from 1.2 to 3.1 bbl/MMcf of separator gas depending upon the test rate. Before the tests, the operator exposed metal coupons in the flow stream of these wells for 18 to 34 days and concluded that corrosive conditions were absent in one well and "slight" in the other. Well F produced gas with only traces of water and hydrocarbon liquid, and the well equipment was thought to be free from the effects of corrosion.

The transmission factors illustrated for 2½-in. tubing in Fig. 3 were constant within the range of experimental error and were independent of the Reynolds number. At Reynolds numbers of 0.824 and 0.832 million, two data points were about 0.8 and 1.8 units, respectively, lower than the average line through the transmission factors. The relative and absolute roughness values for the two points were excluded from the average for all the data. At these lower Reynolds numbers, the pressure loss due to friction in the 2½-in. tubing was low compared to the accuracy of the subsurface-pressure gage causing the probable error in transmission factors to be high at the lower Reynolds numbers. Consequently, the low values of the transmission factors at Reynolds numbers of 0.824 and 0.832 million are believed to be caused by errors in pressure measurement and do not indicate a trend in the data. The average relative roughness was 0.000,530, and the average absolute roughness was 0.000,647 in. for the 2½-in. tubing in the three wells. Transmission factors for Well F were calculated from surface measurement of pressures by Equation (3).

Transmission Factors for 3-in. Tubing

Transmission factors were calculated for the flow of gas through 3-in. tubing (9.30 lb/ft, EUE) from test data taken on three gas wells in Jackson County, Tex., and are illustrated in Fig. 4. These wells produced small quantities of fresh water and hydrocarbon liquid with ratios that varied from 0.4 to 1.5 bbl/MMcf of separator gas, depending upon the flow rate.

The transmission factors for the 3-in. tubing fall into two groups, as shown on Fig. 4. Data for Wells G and H are in reasonable agreement and have an average relative roughness of 0.000,565 and an average absolute roughness of 0.000,846 in. as calculated by the Nikuradse equation for flow in rough pipes. The low value of the transmission factor for a Reynolds number of 1.28 million was caused probably by errors in pressure measurement. This point was excluded from the average roughness values. Transmission factors for Well I are much lower in value than those for Wells G and H. As this difference was consistent and beyond the probable range of experimental errors, a separate set of roughness values was calculated by the Nikuradse equation for flow in rough pipes. The average relative roughness for Well I was 0.006,12 and the average absolute roughness 0.009,15 in.

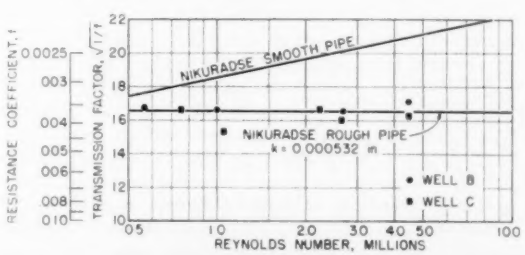

FIG. 2 — EXPERIMENTAL TRANSMISSION FACTORS DETERMINED FOR 2-IN. TUBING (ID—1.995 IN.); LEON COUNTY, TEX.

As the roughness values for the tubing in Well I were in the order of 10 times the magnitude of those for Wells G and H, the operator ran a tubular caliper survey of the tubing in Well I and found that the tubing surface was rougher than usual and that the pits had depths from 8 to 14 per cent of the wall thickness in places. These independent measurements of roughness with a tubular caliper confirm qualitatively the conclusions drawn from the flow tests that the tubing of Well I had an absolute roughness greater than that of Wells G and H.

Transmission Factors for 5½-in. Casing

Flow tests were conducted on three wells with 5½-in. casing (14.0 lb/ft, plain end) to determine the transmission factors shown in Fig. 5. All of these wells were in the Panhandle field in Hartley County, Tex. Although these wells were not equipped with separators, it was believed they produced gas that was relatively free of water and liquid hydrocarbons.

The transmission factors for the 5½-in. casing, as illustrated in Fig. 5, show a trend that differs slightly from that for the various sizes of tubing discussed previously or for the 7-in. casing discussed in the following section. While no definite reason can be assigned for the change, water movement up the flow string may have caused this trend. From experience with tests on short lengths of horizontal pipes, similar trends were observed when water accumulated on the pipe surface.

Relative roughness and absolute roughness values were computed from the transmission factors. Roughness values for five of the 13 transmission factors were excluded in computing the average relative roughness of 0.000,292 and the average absolute roughness of 0.000,732 in. as calculated by the Nikuradse equation for flow in rough pipes. The Nikuradse rough-pipe equation for 5½-in. casing with an absolute roughness of 0.000,732 in. is illustrated in Fig. 5, where the line passes through the experimental data but is not especially indicative of the apparent trend of the data.

Transmission Factors for 7-in. Casing

The transmission factors determined from experimental data on a well with 7-in. casing (24 lb/ft, plain end) and a well with 7-in. casing (22 lb/ft, plain end) are illustrated in Fig. 6. Well M was in Moore County and Well N in Hartley County in the Panhandle field, Tex. Neither well was equipped with a separator, but both wells were believed to produce gas relatively free of water and liquid hydrocarbons.

The average relative roughness and average absolute roughness for Well M were 0.000,103 and 0.000,325 in., respectively, and the values for Well N were 0.000,260 and 0.000,831 in., respectively. Because of this approximately 2.5-fold spread in values, equations of the Nikuradse type for flow in rough pipe with different relative roughness values for both sets of values are shown in Fig. 6. With regard to Well M (Fig. 6), values for two points at the lower Reynolds numbers were excluded from the average absolute roughness of 0.000,325 in. for the well. Except for these two points, the data are in reasonable agreement with the rough-pipe equation, as shown on Fig. 6. The data for Well N, as illustrated in Fig. 6, indicate that the rough-pipe equation for an absolute roughness of 0.000,831 in.

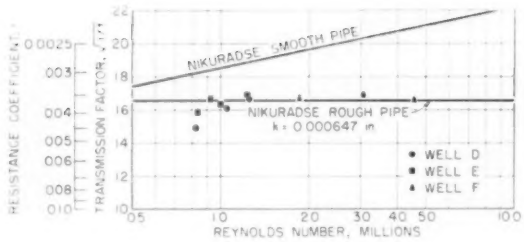

FIG. 3 — EXPERIMENTAL TRANSMISSION FACTORS DETERMINED FOR 2½-IN. TUBING (ID—2.441 IN.); WELLS D AND E, BOSSIER PARISH, LA.; WELL F, CADDO COUNTY, OKLA.

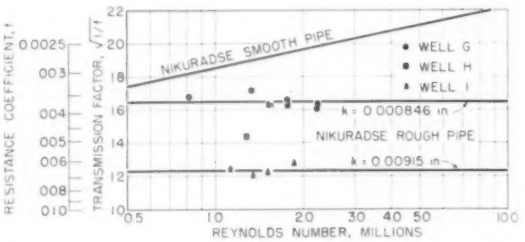

FIG. 4 — EXPERIMENTAL TRANSMISSION FACTORS DETERMINED FOR 3-IN. TUBING (ID—2.992 IN.); JACKSON COUNTY, TEX.

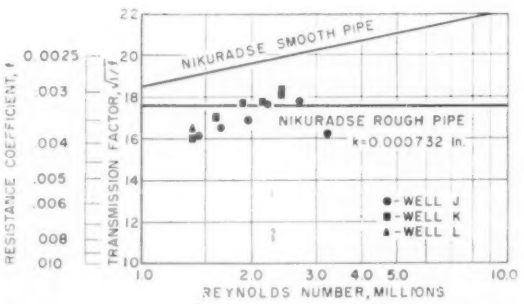

FIG. 5 — EXPERIMENTAL TRANSMISSION FACTORS DETERMINED FOR 5½-IN. CASING (ID—5.012 IN.); PANHANDLE FIELD, HARTLEY COUNTY, TEX.

represents the experimental points within the accuracy of the experimental methods, except for the point at the lowest Reynolds number, which was excluded from the average roughness value.

CORRELATION OF RESULTS

Several means of correlating the results of the study of transmission factors for the flow strings in gas wells were tried, and the conclusion was reached that the Nikuradse equations for flow in smooth pipe and for flow in rough pipe provided one of the best and least complicated methods of correlation. One of the trial methods for correlation was based on the Colebrook[11] equation, which relates the transmission factor to Reynolds number and relative roughness of the pipe sur-

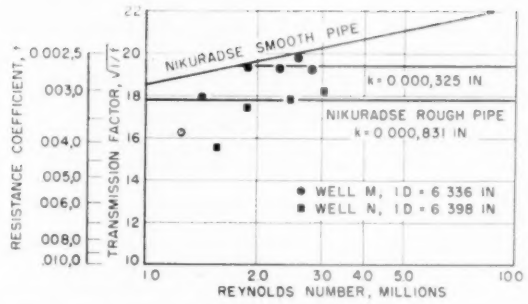

FIG. 6 — EXPERIMENTAL TRANSMISSION FACTORS DETERMINED FOR 7-IN. CASING; PANHANDLE FIELD, HARTLEY AND MOORE COUNTIES, TEX.

face. Colebrook's equation, in units consistent with the foregoing equations, is:

$$\sqrt{1/f} = -4 \log\left(\frac{k}{7.4r} + \frac{1.255}{R}\sqrt{1/f}\right) \quad . \quad . \quad (7)$$

At the lower Reynolds numbers, the Colebrook equation for a given relative roughness is asymptotic to the Nikuradse smooth-pipe equation; and, at the higher Reynolds numbers, it is asymptotic to the rough-pipe equation. In between the two extremes of Reynolds numbers—the transition region—the Colebrook equation forms a smooth curve. None of the data presented in Figs. 1 to 6, inclusive, show a transition region of the type indicated by the Colebrook equation. In addition, experiments conducted by the Bureau of Mines on short lengths of horizontal commercial pipe do not confirm the Colebrook transition relationship. For these reasons, the Nikuradse equations were used for correlating the transmission factors for the flow strings of gas wells. However, the data presented in this report were not taken with the degree of experimental accuracy necessary to justify a rejection of the Colebrook relationship.

A summary of the relative roughness and absolute roughness values as calculated with the Nikuradse equation for flow in rough pipes (Equation 6) is given in Table 1. The relative roughness values vary from a maximum of 0.006,12 for the 3-in. tubing in Well I to 0.000,103 for the 7-in. casing in Well M. Obviously, the relative roughness values for the flow strings of Wells A and I are high, as they are in the order of 6 to 11 fold greater than the next highest value observed (for Wells G and H). If the relative roughness values for Wells A and I are excluded, the values vary from 0.000,103 to 0.000,565—a 5.5-fold variation. These considerations lead to the conclusion that the relative roughness is not constant for the various flow strings.

If the absolute roughness, as shown in the last column of Table 1, is considered and the values for Wells A and I are excluded, the variation in absolute roughness is from 0.000,325 to 0.000,846 in.—a 2.6-fold variation. If the apparently low absolute roughness for Well M is neglected temporarily, the spread is then from 0.000,532 to 0.000,846 in.—a 1.6-fold variation. The relatively small variation in absolute roughness as compared to the variation in relative roughness permits the calculation of an average value of 0.000,65 in., which includes the value for Well M but not the values for Wells A and I.

The average absolute roughness of 0.000,65 in. for the flow strings of gas wells can be used to calculate transmission factors for all sizes of flow strings in gas wells, as is illustrated in Fig. 7, where transmission factor and Reynolds number are the coordinates. The horizontal lines numbered 1 to 5 represent the Nikuradse rough-pipe equation with an absolute roughness of 0.000,65 in. for 2, 2½, and 3-in. tubing and 5½-in. 14 lb/ft and 7-in. 24 lb/ft casing, respectively. These lines representing a constant transmission factor independent of Reynolds number are extended to the lower Reynolds numbers until they meet the line representing the Nikuradse equation for turbulent flow in smooth pipes. Transmission factors for Reynolds numbers less than that at the intersection of the curves for the rough-pipe and the smooth-pipe equations are taken from the smooth-pipe curve at the proper Reynolds number. For example, line 2, representing transmission factors for 2½-in. tubing, meets the smooth-pipe curve at a Reynolds number of 290,000. The transmission factor for 2½-in. tubing at Reynolds numbers above 290,000 is constant at 16.57. Below a Reynolds number of 290,000 the transmission factor is assumed to vary with Reynolds number and should be taken from the Nikuradse curve for flow in smooth pipe—at a Reynolds number of 200,000 the transmission factor for 2½-in. tubing would be 15.98.

The procedure outlined above for estimating transmission factors for the flow strings of gas wells obviously ignores the transition region between smooth turbulent flow and rough turbulent flow that undoubtedly exists for commercial pipe. The transition region occurs at relatively low flow rates for the flow strings of gas wells, so very little error would be introduced in the calculation of pressures at depths below the surface in gas wells. However, it must be stressed that the reported average absolute roughness of 0.000,65 in. does not apply equally to all flow strings in gas wells, but the authors believe that this absolute roughness value will give transmission factors that are more representative of gas-well conditions than those in common use today.

The average absolute roughness of 0.000,65 in. proposed for gas wells in this report agrees very well with an average value of 0.000,6 in. reported by Cullender and Binckley[12]. They calculated their absolute rough-

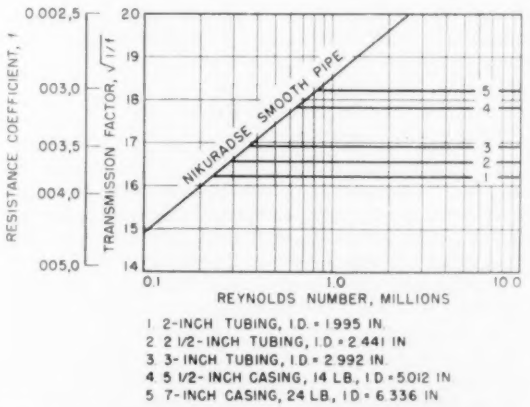
NIKURADSE SMOOTH PIPE
RESISTANCE COEFFICIENT, f
TRANSMISSION FACTOR, √1/f
REYNOLDS NUMBER, MILLIONS
1 2-INCH TUBING, I.D. = 1.995 IN.
2 2 1/2-INCH TUBING, I.D. = 2.441 IN
3 3-INCH TUBING, I.D. = 2.992 IN.
4 5 1/2-INCH CASING, 14 LB., I.D. = 5.012 IN
5 7-INCH CASING, 24 LB., I.D. = 6.336 IN

FIG. 7 — TRANSMISSION FACTORS FOR CIRCULAR FLOW STRINGS COMPUTED WITH THE NIKURADSE ROUGH-PIPE EQUATION; ABSOLUTE ROUGHNESS = 0.000,65 IN.

ness by the Colebrook equation from published data on horizontal pipelines and experimental data obtained on 13 gas wells in the Panhandle and Hugoton fields. Although absolute roughness values computed with the Nikuradse equation for flow in rough pipe are slightly greater than corresponding values computed by the Colebrook equation, the results reported herein and those of Cullender and Binckley are in close agreement.

SUMMARY

A study of the experimental data taken on flow tests conducted on 14 gas wells in Oklahoma, Texas, and Louisiana shows that the transmission factors for the flow strings of these gas wells may be correlated by means of the Nikuradse[10] Equation (5) for turbulent flow of fluids in smooth pipe and the Nikuradse[1] Equation (6) for turbulent flow in rough pipes. Most of the transmission factors presented in this report can be represented by the Nikuradse equation for flow in rough pipe, using a relative roughness which varies with the size of the pipe. However, the absolute roughness as calculated from the relative roughness was found to be fairly constant at an average value of 0.000,65 in. for 12 of the 14 wells tested.

The average value of 0.000,65 in. for the absolute roughness may be used with the Nikuradse Equation (6) for the flow of fluids in commercial pipe to calculate transmission factors for the flow strings of gas wells providing the proper Reynolds number restrictions are observed. The Nikuradse resistance equation for flow in rough pipe for the average absolute roughness of 0.000,65 in. and a given pipe radius will meet the Nikuradse equation for flow in smooth pipe at a certain Reynolds number. For flow at Reynolds numbers less than the Reynolds number at the intersection, the pipe may be considered "smooth," and the transmission factor is determined by the Reynolds number and the smooth-pipe equation. For flow at Reynolds numbers greater than the Reynolds number at the intersection, the relative roughness of the pipe may be considered to be the only variable influencing the transmission factor; therefore, the transmission factor may be calculated from the pipe radius, the average absolute roughness of 0.000,65 in. and the equation for flow in rough pipes.

Transmission factors calculated by the methods outlined in this report are believed to be representative of the flow strings of gas wells and may be used in calculating subsurface pressures in flowing gas wells from measured wellhead pressures.

ACKNOWLEDGMENTS

The study by the Bureau of Mines of the productivity of gas wells is being carried on in cooperation with the American Gas Association. The assistance given by E. L. Rawlins, chairman, Gas-Well Deliveries Subcommittee of the Operating Section, American Gas Association, is gratefully acknowledged.

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The authors acknowledge the assistance and suggestions offered in the preparation of this paper by: C. W. Binckley of Phillips Petroleum Co., and J. W. Ferguson of Continental Oil Co.; and C. J. Wilhelm, C. K. Eilerts, R. V. Higgins, and E. M. Tignor of the Bureau of Mines.

SYMBOLS USED IN EQUATIONS

D = internal diameter of pipe, feet
d = internal diameter of pipe, inches
e = natural logarithm base = 2.718,28
f = resistance coefficient, dimensionless
$\sqrt{\frac{1}{f}}$ = transmission factor, dimensionless
G = specific gravity of fluid, air = 1.0
g = acceleration of gravity (conversion factor)
k = absolute roughness, inches (height from peak to valley of a hypothetical uniform roughness profile)
$\frac{k}{r}$ = relative roughness, ratio
L = depth of flowing column of fluid, feet
L_s = energy required to lift 1 lb of the fluid from a depth L in the well, foot-pound (as 1 lb of fluid is under consideration L_s is numerically equal to L)
P = pressure, psia
P_s = subsurface pressure at depth L in the well, psia
P_w = wellhead pressure, psia
Q = volume rate of flow, cubic feet per 24 hours (pressure base = 14.4 psia and temperature base = 60° F)
R = Reynolds number, dimensionless
r = radius of pipe, inches
S = density of fluid, pounds per cubic foot
s = exponent of e in Equation (3) = $0.037{,}504\frac{GL}{TZ}$
T = effective temperature, °F absolute
U = average linear velocity, feet per second
v = specific volume, cubic feet per pound
Z = effective compressibility of gas, dimensionless
μ = viscosity of fluid, pounds per second foot
log is to base 10

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THE PUMPABILITY of CLAY-WATER DRILLING FLUIDS

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T. P. 3930

ABSTRACT

Various methods have been proposed in the literature to calculate the pressure losses in drill-pipe and bit-nozzles, i.e., those parts of the mud-circuit where the largest pressure-losses occur. Very few data, however, are available to check the validity of these proposals.

Presented in this paper are the results of pumping experiments with clay-water drilling fluids of different specific gravities and different laminar flow-properties (differential viscosity and Bingham yield value), using pipes of different diameters. In addition, a series of measurements on bit-nozzles is discussed.

Two main conclusions may be drawn from this work for the flow through pipes.

1. In the laminar flow region pressure losses can be calculated from the differential viscosity and Bingham yield value of the mud.

2. In the turbulent flow region pressure losses can be calculated with good approximation from a viscosity term which is determined by the volume fraction of the dispersed phase. Calculations making use of laminar flow properties may lead to erroneous results. The effect of temperature on the pressure losses in the case of turbulent flow can be calculated from the change in viscosity of the dispersing medium, i.e., water.

The main conclusions determined for the flow through bit-nozzles are that for flow conditions prevailing in the field, the pressure-drops in bit-nozzles are independent of the laminar flow properties of the mud. They are solely determined by the density of the mud and the geometry of the nozzle.

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[1]References given at end of paper.

INTRODUCTION

The last decades have witnessed a steady increase in the depth of oil wells. This is illustrated by the increase in the drilling depth record in the USA from 8,046 ft in 1927 to 21,482 ft in 1953. This increasing depth, together with the experience that high rates of mud circulation and high fluid velocities in the bit-nozzles enhance the rate of drilling, has emphasized the importance of selecting suitable mud-pumps when starting the drilling of a deep borehole.

For such a selection it is necessary to be able to calculate the pumping pressures necessary to obtain the required circulation rates. The main part of the pressure-losses in the mud circuit occur in the drill pipe and the bit-nozzles. Various methods have been proposed in the literature to calculate the pressure-losses in the drill pipe[1,2,3,4]. These methods do not all lead to the same results, and at the time this investigation was started insufficient basic data were available to check their validity. Moreover, to our knowledge, no data are available at all on the effect, if any, of the flow-properties of the mud on the pressure-losses in bit-nozzles.

The work described in this paper was carried out to collect basic data on the subject. It is to be considered as a continuation of Van Olphen's work in this field[5,6].

FLOW BEHAVIOR OF MUDS

Various authors[2,7,8] have shown that clay water-muds approximately behave as Bingham fluids; the main part of the curve relating the rate of shear D to the shearing stress τ can be represented by the formula $\tau - \tau_B = nD$.

Laminar Flow in Pipes

For laminar flow of a Newtonian fluid through a pipe, the Poiseuille equation is valid:

$$Q = \frac{\pi R^4}{8\eta l} P \quad \ldots \ldots \ldots \ldots \quad (1)$$

The corresponding formula for a Bingham fluid is the Bingham-Buckingham equation:

$$Q = \frac{\pi R^4}{8nl} \left\{ P - \frac{4}{3} p_o \left(1 - \frac{p_o}{4P}\right) \right\} \quad \ldots \quad (2)$$

where $p_o = \frac{2l\tau_B}{R} \quad \ldots \ldots \ldots \ldots \quad (3)$

The flow is characterized by the presence of a plug in the center of the pipe. When P becomes large as compared with p_o (which is normally the case), Equation (2) becomes:

$$Q = \frac{\pi R^4}{8nl} \left\{ P - \frac{4}{3} p_o \right\} \quad \ldots \ldots \quad (4)$$

When comparing Equation (4) with Equation (1) it may be seen that the viscosity η in Equation (1) has been replaced by the term:

$$n + \frac{\pi R^3 \tau_B}{3Q} = n + \frac{R}{3V} \tau_B$$

which term is called the apparent viscosity (η_a).

The Onset of Turbulence

For Newtonian fluids, flow becomes turbulent when

$$Re\text{-number} = \frac{2RV\rho}{\eta} = 2000\text{-}3000.$$

According to Binder and Busher[9] the flow of Bingham fluids becomes turbulent when

$$\frac{2RV\rho}{\eta_a} = \frac{2RV\rho}{n + \frac{R}{3V}\tau_B} = 2000\text{-}3000$$

McMillen[10] introduces a Re-number in which R is replaced by δ, the distance from the wall. Instead of η he uses the apparent viscosity corresponding with the rate of shear prevailing at this distance δ. When this Re-number exceeds the value 2,000 to 3,000 at any point of the tube, flow becomes turbulent at that point. According to this theory turbulence begins somewhere between the wall and the plug.

Hedstrom[11] assumes that laminar flow begins when the calculated laminar flow-curve crosses the calculated turbulent flow-curve. The latter curve is computed with Equation (5) assuming that the turbulent viscosity is equal to the differential viscosity. For the calculation of the critical rate of flow he uses two dimensionless quantities *viz.* $Re = \frac{2RV\rho}{n}$ and $S = \frac{2R\tau_B}{nV}$.

It is shown that the critical Re-number depends on the value of S. A graph is given in Hedstrom's paper from which Re_{cr} may be derived when S is known.

Turbulent Flow

When flow is turbulent, the relation between pressure and volume rate of flow in circular pipes reads for Newtonian fluids:

$$P = f \frac{l\rho Q^2}{\pi^2 R^5} \quad \ldots \ldots \ldots \ldots \quad (5)$$

In this formula f is a dimensionless quantity, called the friction-factor, which is a function of Re-number and roughness of the pipe.

It is generally agreed that Equation (5) should also be used for the calculation of pressure-losses in the case of Bingham-fluids. Of importance is the question which viscosity-value should be substituted in the Re-number, in order to find the right value for f.

The opinions as to which value should be taken for this turbulent viscosity (η_t) are widely divergent. According to Caldwell and Babbitt,[7] η_t is equal to the viscosity of the dispersing medium. The pressure drop calculations given by Koch[4] are based on this assumption.

In a pamphlet issued by Hughes Tool Co.[2] graphs are given which are based on the assumption that drilling-muds have a turbulent viscosity of 3 cp. Dunn, Nuss and Beck[3] are of the opinion that the relation $\eta_t = 1/3.2n$ holds true. Hedstrom[11] found indications that $\eta_t = n$, whereas Van Olphen[6] found $\eta_t = 1.5\,n$.

Pressure-Losses in Bit-Nozzles

In the case of Newtonian fluids the pressure-drop, when forcing a fluid through a stricture, is given by:

$$\Delta P = \frac{\rho Q^2 (1-\beta^4)}{2C^2 A^2} \quad \ldots \ldots \ldots \quad (6)$$

To our knowledge, no data exist on the influence of the Bingham yield value and differential viscosity on the value of C (coefficient of discharge). Usually C is considered to be independent of the fluid properties and is given a constant value.

Summarizing the above, there seems to exist no unanimity for Bingham fluids as regards: (a) criteria for the onset of turbulent flow; (b) the magnitude of the turbulent viscosity, and (c) the influence of the flow-properties on the pressure-losses in bit-nozzles. The experiments described in this paper were intended to shed more light on these points.

EXPERIMENTAL PROCEDURE

Flow Experiments on Pipes and Nozzles

The muds were pumped through pipes of 8 m length and of different diameter (1, 2 or 3 cm) by means of a small mud-pump (maximum capacity 100 gal./min).

Experiments on smaller pipes (diameter of 0.6 and 0.8 cm and a length of 1 m) were carried out with the aid of a 10 gal pressure vessel to which the various pipes could be attached. By means of compressed air the mud was forced through the pipes.

The pressure drops in the pipes were measured with either a mercury or a Bourdon type manometer at a sufficient distance from beginning and end of the tubes to avoid the influence of end effects.

In the experiments on nozzles the mud was pumped through a nozzle of 0.4 cm diameter by means of the above mud-pump. Recovery of kinetic energy of the fluid was avoided by placing a wide vessel behind the nozzle, in which the kinetic energy was transformed into heat.

Measurement of Differential Viscosity and Bingham Yield Value

For the determination of these flow-properties use was made of two rotational viscometers, which both had a small clearance between cup and rotor, the Stormer viscometer as modified by Van Olphen [2], and a motor-driven viscometer *. An important advantage of the latter is that the pre-treatment of the mud can be continued until no further structural break-down of the mud occurs.

SURVEY OF EXPERIMENTS

A first series of tests covered the whole flow-curve viz. laminar flow, the onset of turbulence and turbulent flow.

It comprised the following experiments:

(a) Clay water muds with a density of 1.31 gm/cm³ (10.9 lb/gal.) and different rheological properties were pumped through a pipe of 2 cm diameter.

(b) Muds with a density of 1.69 gm/cm³ (14.1 lb/gal.) and different rheological properties were pumped through pipes of 1 and 2 cm diameter. These muds are prepared from the former muds by loading with barytes.

The rheological properties were varied by adding flocculating or peptising agents (e.g. NaCl, quadraphos).

A second series of experiments more especially dealt with the turbulent part of the flow-curve:

(a) Experiments with two bentonite muds loaded with barytes with densities of 1.26 gm/cm³ (10.5 lb/gal.) and 1.55 gm/cm³ (12.9 lb/gal.) in which the influence of temperature on the turbulent visocity η_t was investigated.

(b) Experiments with clay-water muds of different densities, viz. from 1.10 gm/cm³ (9.2 lb/gal.) to 1.40 gm/cm³ (11.7 lb/gal.), in which the influence of the rate of flow and pipe diameter on η_t was studied. These experiments further served the purpose of investigating the relation, if any, between the differential viscosity and η_t and between the volume fraction of dispersed phase and η_t.

(c) Experiments with muds containing 6 per cent bentonite, loaded with barytes with densities from 1.15 gm/cm³ (9.6 lb/gal.) to 1.75 gm/cm³ (14.6 lb/gal.).

(d) Finally, the η_t-values of some field muds were determined, viz.: a clay-water mud with a density of 1.17 gm/cm³ (9.8 lb/gal.), treated with flocgel (a modified starch); a saturated salt water mud with a density of 1.37 gm/cm³ (11.4 lb/gal.), also treated with flocgel, and a red mud with a density of 1.30 gm/cm³ (10.9 lb/gal.).

A third series of experiments dealt with the pressure drops in bit-nozzles. The muds from the first series were also used here.

In all cases the *f-Re* relations, valid for the various pipes, and the *C-Re* relations for the nozzles were determined with the aid of water. These measurements were repeated regularly during the above experiments in order to trace possible changes in these relations.

DISCUSSION OF RESULTS

Experiments Covering the Whole Flow-Curve

By way of example the results obtained with the muds having a density of 1.31 gm/cm³, pumped through a pipe of 2 cm diameter are presented in Fig. 1.

The Laminar Flow Region

If the two rotational viscometers provide the right values for the differential viscosity and the Bingham yield value of the mud, the pressure losses calculated by means of the Bingham-Buckingham Equation (2) should correspond with those actually observed.

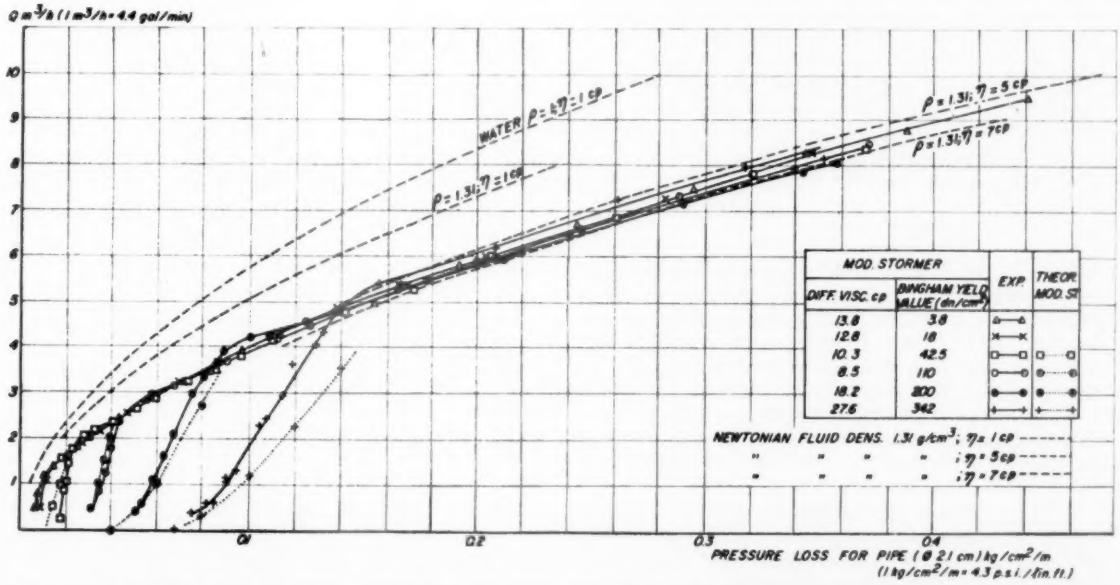
Q m³/h (1 m³/h = 4.4 gal/min)
WATER ρ = 1 ; η = 1 cp
ρ = 1.31 ; η = 1 cp
ρ = 1.31 ; η = 5 cp
ρ = 1.31 ; η = 7 cp
MOD. STORMER
DIFF. VISC. cp
BINGHAM YIELD VALUE (dn/cm²)
EXP
THEOR. MOD. ST.
13.8 3.8
12.8 18
10.3 42.5
8.5 110
18.2 200
27.6 342
NEWTONIAN FLUID DENS. 1.31 g/cm³; η = 1 cp
η = 5 cp
η = 7 cp
PRESSURE LOSS FOR PIPE (Ø 2.1 cm) kg/cm²/m
(1 kg/cm²/m = 4.3 p.s.i./fin.ft.)

FIG. 1 — PRESSURE LOSS-VOLUME RATE OF FLOW DATA FOR A MUD WITH VARYING RHEOLOGICAL PROPERTIES: MUD DENSITY 1.31 GM/CM³; PIPE DIAMETER 2.1 CM.

*Developed by H. C. Darley: Shell Development Co.'s Exploration and Production Research Div., Houston, Tex.

TABLE 1 — COMPARISON OF LAMINAR FLOW PROPERTIES WITH THE TURBULENT VISCOSITY

Density of mud g/cm³	Pipe diameter cm	τ_B dn/cm² Modified Stormer viscometer	τ_B dn/cm² Motor driven viscometer	τ_B dn/cm² Pipe	n Modified Stormer viscometer	n Motor driven viscometer	n Pipe	η_t at 20° C in cp.
1.31	2.1	3.8	10.6	15.5	13.8	10.9	9.3	5.7
1.31	2.1	18.5	16.0	28.3	13.0	11.8	6.9	6.1
1.31	2.1	42.5		65	10.3		6.8	6.4
1.31	2.1	112	126	121	9.3	19.8	8.6	6.3
1.31	2.1	200		189	18.2		15.5	6.0
1.31	2.1	342		325	26.0		16.8	5.8
1.69	2.1	35	45	39	31.0	15.0	19.3	9.5
1.69	2.1	172	209	206	28.0	16.0	14.0	8.4
1.69	2.1	288		280	51.0		18.0	8.0
1.69	1.0	30	31	96	27.0	14.7	13.1	9.1
1.69	1.0	107	114	192	23.7	14.9	12.9	8.7
1.69	1.0	258	265	420	49.5	28.0	18.9	9.4

In the case of muds of 1.31 gm/cm³ density and of not too high yield values (e.g. lower than 200 dn/cm²) the agreement is reasonable (Fig. 1). However, for higher Bingham yield values substantial deviations may occur (e.g. 20 per cent). The deviations are even more pronounced with the muds of 1.69 gm/cm³ density (sometimes 50 per cent). In most cases the calculated pressures are higher than the observed pressures. This is mainly caused by the fact that the viscometers give higher values for n than correspond with pipe flow data. This is illustrated in Table 1, where τ_B and n derived from pipe-flow data (with Equation 4) are compared with the viscometer values.

These deviations are probably connected with the influence of agitation on the flow-properties (thixotropy). This agitation is strongest in the pumping experiments. The deviations are smallest at low τ_B-values because then the influence of agitation is smallest. The motor-driven viscometer gave better results at higher τ_B-values than the modified Stormer viscometer, probably because with the former viscometer a longer pretreatment was given to the mud.

The Onset of Turbulence

From the flow-curves a critical rate of flow may be derived at which turbulence begins (cf Fig. 1). To check the validity of the various criteria for predicting the critical rate of flow Re-numbers have been calculated according to the various methods proposed in the literature. For these calculations the Bingham yield value and the differential viscosity derived from the laminar part of the pipe flow curve have been used. The critical Re-numbers as defined by Binder and Busher and by McMillen should have a value of 2,000 to 3,000, whereas the critical value of Hedstrom's Re-number is dependent on the value of $S\ (= \frac{2R\tau_B}{nV})$.

In Table 2 the values for Re_{cr}, derived from the flow-curves are compared with those postulated by the above authors. It is seen that Binder and Busher's method predicts the onset of turbulence with reasonable accuracy. In the case of muds with a density of 1.31 gm/cm³, Re_{cr} is somewhat low, but the transition region is rather large and the lowest possible Q_{cr} value has been used in the calculation. Hedstrom's method also appears to provide a reasonable criterion for determining whether flow is laminar or turbulent.

Finally, it appears that McMillen's method is not suitable in the cases investigated here: the value of his Re_{cr} is considerably lower than 2,000 to 3,000. This means that the critical rate of flow as predicted by McMillen would be too high. The reason possibly is that these muds do not behave exactly as Bingham fluids.

The Turbulent Flow Region

By means of Equation (5), the friction factor f corresponding with the rate of flow Q could be calculated from the turbulent part of the flow curves. From this friction factor and the relationship between f and Re as determined with water, a Re-number $\frac{2Q\rho}{\pi\eta_t R}$ was derived, which was used for computing the turbulent viscosity η_t. All experiments were carried out with smooth pipes, which closely follow the Blasius equation. The experiments indicated that η_t is independent of the rate of flow.

In Table 1 the values of the turbulent viscosity of the muds are compared with their differential viscosities and Bingham yield values as measured with the viscometers and derived from pipe flow data. The η_t-values in this table have been calculated from the observed η_t-values and the temperature at which the experiments were carried out according to a method described in the next section.

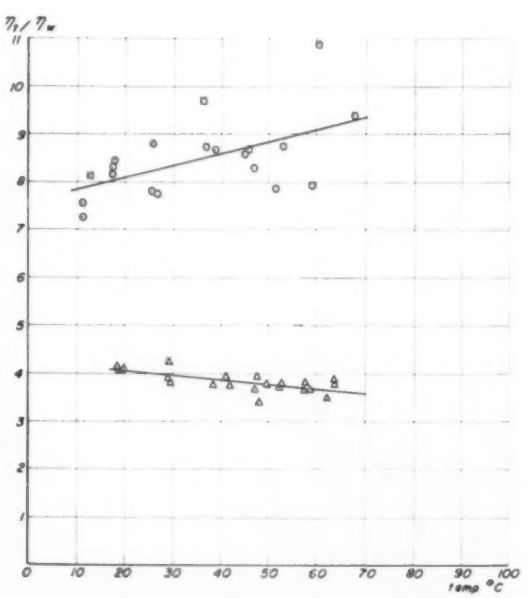

FIG. 2 — INFLUENCE OF TEMPERATURE ON η_t/η_w BENTONITE-BARYTES MUD WITH A DENSITY OF 1.26 GM/CM³△. BENTONITE-BARYTES MUD WITH A DENSITY OF 1.55 GM/CM³●.

TABLE 2 — COMPARISON BETWEEN SOME METHODS OF CALCULATING THE ONSET OF TURBULENCE

Mud density gm/cm³	Pipe diameter cm	τ_B pipe dn/cm²	η_{pipe} cp	Q_{cr} gal/min	Binder and Busher[9] Re_{cr} from curves	Binder and Busher[9] Re_{cr} expect.	McMillen[10] Re_{cr} from curves	McMillen[10] Re_{cr} expect.	Hedstrom[11] Re_{cr} from $\frac{2Q_{cr}\rho}{n\pi R}$	Hedstrom[11] Re_{cr} via $S = \frac{2R\tau_B}{nV}$
1.31	2.1	28.3	6.9	4.4	1150	2000-3000	174	2000-3000	3210	4500
		15.5	9.3	5.3	1770		464		2850	2500
		65	6.8	7.7	1690		240		5670	6000
		121	8.6	9.9	1560		407		5820	7000
		189	15.5	13.6	1620		261		4420	4500
		325	16.8	15.8	1420		200		4740	6000
1.69	2.1	39	19.3	7.5	1650	2000-3000	490	2000-3000	2500	2450
		206	14.0	13.6	2050		314		6300	5300
		280	18.0	17.6	2330		388		6320	4500
1.69	1.0	96	13.1	3.5	2625	2000-3000	827	2000-3000	3760	2400
		192	12.9	4.0	2470		616		4300	2750
		420	18.9	5.6	1505		514		4080	2900

Table 1 clearly illustrates that η_t is not influenced by the degree of flocculation of the mud (the variation in τ_B and n was effected by adding flocculating or peptising agents).

With respect to the magnitude of η_t it may be remarked that η_t is higher than the viscosity of the dispersing medium and lower than the differential viscosity. The table further shows that $\frac{n}{\eta_t}$ is not a constant as assumed by Dunn et al. This point is further illustrated in Table 3 A and B.

The Turbulent Viscosity

When comparing the turbulent viscosites of the two muds investigated with the viscosity of water at the corresponding temperature, it appears that their quotient is practically independent of temperature. This is illustrated in Fig. 2. In the one case $\frac{\eta_t}{\eta_w}$ slightly increases, in the other case it slightly decreases with temperature. If there is any influence of t on $\frac{\eta_t}{\eta_w}$, this is so small that it may be neglected for practical purposes. This fact may be used for calculating η_t at any temperature, when its value at one temperature is known.

TABLE 3A — QUOTIENT $\frac{n}{\eta_t}$ FOR DIFFERENT CLAY-WATER MUDS

Mud density gm/cm³	τ_B dn/cm² Motor driven viscom-eter	n cp Modified Stormer viscom-eter	n cp Motor driven viscom-eter	η_t cp at 20°C	$\frac{n}{\eta_t}$ Modified Stormer viscom-eter	$\frac{n}{\eta_t}$ Motor driven viscom-eter
1.31	3.8	13.8	10.9	5.7	2.4	1.9
1.31	112	9.3	19.8	6.3	1.5	3.1
1.31	200	18.2		6.0	3.0	
1.69	35	31.0	15.0	9.9	3.1	1.6
1.69	30	27.0	14.7	9.1	3.0	1.6
1.69	258	49.5	28.0	9.4	5.3	3.1
1.10	0	3.0	3.3	2.0	1.5	1.7
1.10	8	4.3	5.0	2.25	1.9	2.2
1.20	20	6.6	5.2	3.9	1.7	1.3
1.20	20	6.6	5.2	3.2	2.1	1.6
1.40	35	21.8	17.1	9.7	2.2	1.8
1.15	30	13.5	11.1	3.0	4.5	3.7
1.15	30	13.5	11.1	4.2	3.2	2.7
1.54	70	16.4	14.4	8.0	2.0	1.8
1.54	80	19.8	19.3	8.3	2.4	2.3
1.18	7.5	5.3	6.4	3.7	1.4	1.7
1.31	33	27.4	19.3	13.1	2.1	1.5

TABLE 3B — SOME $\frac{n}{\eta_t}$ VALUES FOUND BY DUNN ET AL. ON 2-IN. TUBING

Mud No.	n cp	η_t cp	$\frac{n}{\eta_t}$
1	30	9.0	3.3
2	10.2	4.8	2.1
3	17.1	8.1	2.1
4	26.1	7.1	3.7
5	39.0	12.6	3.3
6	15.9	2.5	6.4
7	5.1	2.7	1.9

All experiments described have not been carried out at the same temperature. If necessary, the results of these experiments will be compared on the basis of $\frac{\eta_t}{\eta_w}$.

In Fig. 3 the results of pumping experiments with clay-water muds at different rates of flow are presented. It appears that η_t is independent of the rate of flow. Measurements on the barytes-loaded bentonite muds confirmed this observation.

The results of experiments on the bentonite muds with barytes and pipes of different diameter are presented in Fig. 4. No significant influence of pipe diameter on η_t/η_w was observed. This was again confirmed by measurements on the clay-water muds without barytes.

In the section on turbulent flow it was noted that n/η_t is not a constant. To further illustrate this a series of n/η_t-values, representative for our experiments have been collected in Table 3A. The η_t-values at 20°C and the n-values at room temperature are given. The table shows large variation in n/η_t-values. The quotient n/η_t has also been calculated for some data given by Dunn et al. (Table 3B). The figures again show a considerable spread. From this it may be concluded that methods

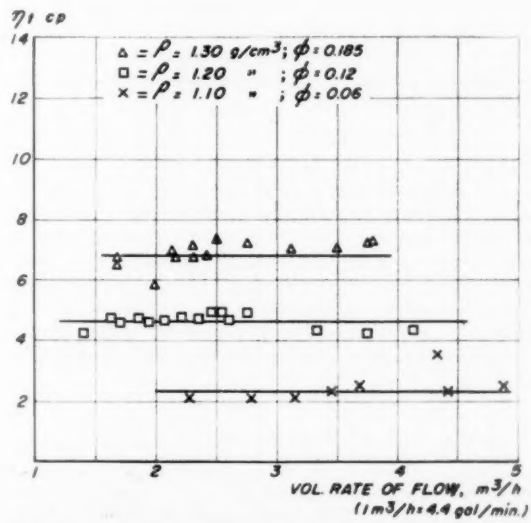

FIG. 3 — THE INFLUENCE OF RATE OF FLOW ON THE TURBULENT VISCOSITY OF CLAY WATER MUDS (PIPE DIAMETER 1.0 CM).

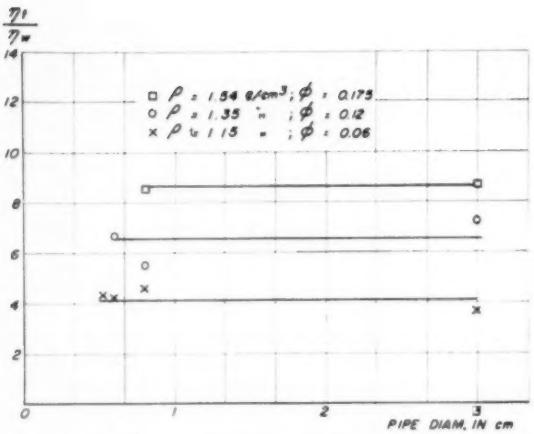

FIG. 4 — INFLUENCE OF PIPE DIAMETER ON η_t/η_w FOR MUDS PREPARED FROM BENTONITE AND BARYTES.

based on the assumption that n/η_t is a constant may lead to erroneous results.

In Fig. 5 the influence of the volume fraction of dispersed phase ϕ* on $\frac{\eta_t}{\eta_w}$ is shown for clay water muds and bentonite muds loaded with barytes. As explained earlier, the position of the points in this graph is not influenced by the degree of flocculation of the mud. Each point represents the average of in total *ca.* 40 measurements on three or four pipes of different diameter. The standard deviation in such a group of measurements varies from 10 to 25 per cent.

It appears that the η_t/η_w-values of the bentonite-barytes muds are higher than those for the other muds. However, no value deviates more than 30 per cent from the average η_t/η_w-values of the two types of muds.

The results of measurements on field muds are also presented in Fig. 5. For the case of the saturated salt water mud the viscosity of a saturated salt solution (2.2 cp at 20°C) has been used instead of η_w. The best straight line through all the points follows the equation:

$$\frac{\eta_t}{\eta_w} = 46.5\,\varphi \quad \ldots\ldots\ldots\ldots \quad (7)$$

The field mud with a φ-value of 0.185 shows a deviation of 43 per cent, whereas the η_t-values of all other muds deviate less than 40 per cent from the line. It should be borne in mind that the pressure losses vary as the fourth root of the η_t-value. This means that when using Equation 7 to predict η_t/η_w, the pressure-losses may be calculated with an accuracy of ± 10 per cent approximately. The relation between f and Re has to be known for these calculations. Probably for drill pipes the Blasius equation ($f = 0.079\,Re^{-1/4}$) may be used, because usually their surface will be smooth, as a result of the polishing action of the mud.

Though not perfect, the above method of predicting η_t from φ is more accurate than methods which use the differential viscosity for this purpose.

EXPERIMENTS WITH BIT-NOZZLES

By way of example the relation between C and Re as determined with water is presented in Fig. 6 for one of the nozzles used in these experiments. It appears that C decreases with increasing Re-number to become practically constant at a Re-number of 150,000.

From the steep part of the C-Re-curve and the C-values obtained via Equation (6) from pumping experiments with muds, the η_t-values of these muds could be derived. The C-Re relation at high Re-numbers could not be used because it gives too inaccurate values of η_t. It appeared that the η_t-values thus obtained are independent of rate of flow and of the laminar flow-properties of the mud.

An average value of 1.75 cp was obtained for muds with a density of 1.31 gm/cm³ and of 1.9 cp for muds with a density of 1.69 gm/cm³. In Fig. 6 the C-values of a mud with a density of 1.31 gm/cm³ are plotted against a Re-number computed with an η_t-value of 1.75, which illustrates that the points so obtained fall on the

* ϕ can be calculated from the equation $A + (1 - \phi) \cdot \rho_{fl} = \rho_m$ where ϕ = volume fraction of dispersed phase, A = grams of dispersed phase per ml mud (= grams dry weight of 1 ml mud minus grams dissolved salts per ml mud), ρ_{fl} = density of medium and ρ_m is density of mud. A and ρ_m can be determined experimentally. In the case of water base muds, ρ_{fl} is unity. Dissolved salts do not contribute to ϕ, but they affect η_m (the viscosity of the medium) and ρ_{fl}. In this case, η_m and ρ_{fl} have to be determined or may be derived from tables.

* 100 m³ water/hour through four ¾-in. nozzles already corresponds with a Re-number of 100,000.

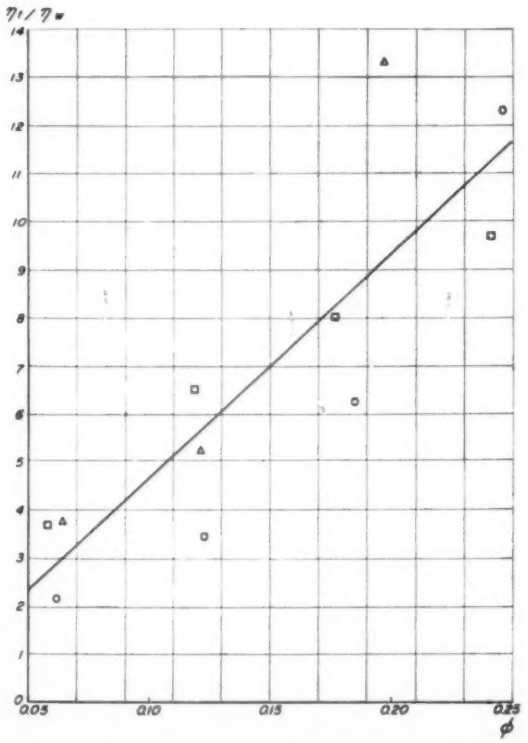

FIG. 5 — THE RELATION BETWEEN η_t/η_w AND THE VOLUME FRACTION OF DISPERSED PHASE ϕ; CLAY MUDS ○; BENTONITE-BARYTES MUDS □; FIELD MUDS △.

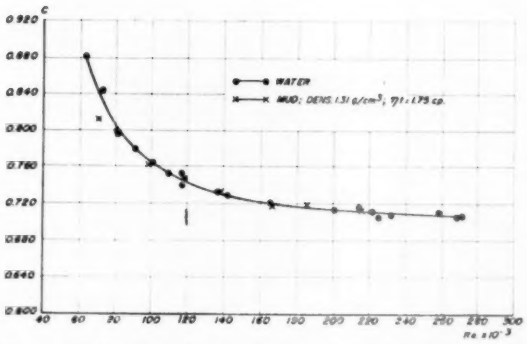

FIG. 6 — NOZZLE EXPERIMENTS; *C-Re* RELATIONSHIPS FOR MUD AND WATER.

waterline. In the field the flat part of the *C-Re* curve is of importance*. This means that under field conditions the *C*-value for a mud is the same as that for water. Its magnitude is only determined by the geometry of the nozzle. If the nozzle has been designed well[12], it has a coefficient of discharge which lies between 0.9 and 1.0.

CONCLUSIONS

1. When clay-water muds are pumped through pipes, pressure losses in the laminar flow region may be calculated — though not very accurately — from the differential viscosity of the muds as measured with rotational viscometers (The data obtained with the motor-driven viscometer were found to be better suited for the purpose than those found with the modified Stormer viscometer).

2. The criterion of Binder and Busher[9] or that of Hedstrom[11] may be used to calculate whether the flow of a clay-water mud in a pipe is laminar or turbulent. McMillen's[10] criterion is not suitable for clay-water muds in that it gives too high values for the critical rate of flow.

3. The turbulent viscosity of a clay-water drilling mud is not influenced by: (a) the degree of flocculation of the mud; (b) the rate of flow; and (c) the diameter of the pipe.

4. The quotient of the turbulent viscosity of a clay-water mud and the viscosity of water at the same temperature is practicially independent of temperature.

5. This quotient may be predicted with reasonable accuracy from the volume fraction of dispersed phase.

6. The turbulent viscosity of a clay-water mud is not equal to the viscosity of the dispersing medium[3], nor to the differential viscosity of this mud[11].

7. The quotient of the differential viscosity and the turbulent viscosity is not a constant[3,6]. The use of such a relation to calculate pressure-losses may lead to erroneous results.

8. For flow conditions prevailing in the field, the pressure-losses in the bit-nozzles are independent of the laminar flow properties of the mud; they are solely determined by the density of the mud and the geometry of the nozzle.

ACKNOWLEDGMENT

The author wishes to thank J. van Heiningen and L. J. Klinkenberg for valuable discussions on the subject, and to A. Luyt, R. Eype and W. A. M. van der Wielen for carrying out the experimental work. He further expresses his appreciation to the management of the N. V. De Bataafsche Petroleum Maatschappij, The Hague, Netherlands for permission to publish this paper.

LIST OF SYMBOLS

β = ratio of nozzle diameter to tube diameter
Φ (ϕ) = volume fraction of dispersed phase
η = dynamic viscosity in poises
η_a = apparent viscosity in poises
η_m = viscosity of dispersing medium in poises
η_w = viscosity of water in poises
η_t = turbulent viscosity of mud in poises
η_t/η_a = quotient of η_t and η_a at the same temperature
ρ = density gm/cm³
τ = shear stress dn/cm²
τ_o, τ_B = gel strength and Bingham yield value dn/cm²
A = cross sectional area of nozzle in cm²
C = coefficient of discharge, dimensionless
D = rate of shear second⁻¹
l = length of tube in cm
n = differential viscosity in poises
P or $\triangle P$ = pressure drop over pipe or nozzle in dn/cm²
Q = volume rate of flow in cm³/sec
R = tube radius in cm
Re = Reynolds' number
Re_{cr} = critical Reynolds' number
t = temperature in degrees centigrade
V = linear rate of flow cm/sec

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MEET the AUTHORS

MURRAY F. HAWKINS, JR., is professor of petroleum engineering at Louisiana State University, having been at LSU since 1946. He holds a BS degree in physical chemistry and a MS degree in physics. He has been employed by Carter Oil Co., U.S. Navy Department, and the Ethyl Corp.

MARION L. KIMMEL has been an assistant petroleum engineer in the reservoir engineering section of The Ohio Oil Co.'s Houston Division for 2½ years. He received his BS degree in mechanical engineering from Kansas State College in 1950 and his MS degree in petroleum engineering from LSU in 1952.

PETER DEHLINGER has recently accepted a position as associate professor of geophysics in the Department of Geology at Texas A&M College. Prior to this, he has worked with Continental Oil Co., Battelle Memorial Institute, and the Shell Oil Co. He holds a PhD degree in geophysics from California Institute of Technology. The research summarized in T.P. 3929 was done while he was at Battelle.

WILLIAM H. BROWNE is head of Battelle Memorial Institute's research activities in mechanical engineering. He came to Columbus, Ohio, to join Battelle in 1942 after working for six years on the research staff of Caterpillar Tractor Co. He is a 1936 mechanical engineering graduate of Rensselaer Polytechnic Institute.

C. O. BUNDRANT is chief chemical engineer for The Western Co. in Midland. In 1945 he received a research fellowship at Texas Tech College sponsored by The Western Co. In 1947, after receiving his BS degree in chemical engineering, he joined The Western Co. organization.

R. V. SMITH is technical advisor to the chief production engineer of the Natural Gas Department, Phillips Petroleum Co. Before recently accepting this position, he had worked with the Bureau of Mines since 1936. He holds AB and AM degrees from the University of Missouri in physical chemistry.

(Continued on Page 61)

PERSONALS

WALLACE E. PRATT, 1948 recipient of the AIME Anthony F. Lucas Medal, has been awarded the API Gold Medal for Distinguished Achievement. The former vice-president and director of Standard Oil Co. (N.J.) now resides near Carlsbad, N.M. He is an internationally known geologist, author, and philosopher.

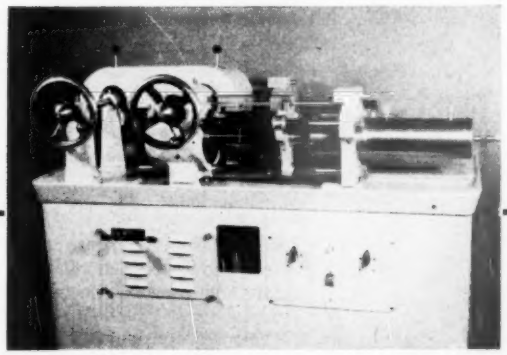
VIRGIL D. STONE has been promoted to area drilling foreman for the Gulf Refining Co. with offices in Cut Off, La. Recently elected to AIME membership, he was serving as petroleum engineer at the time of his promotion.

HOWARD E. ROTHROCK, consulting geologist, has moved to Coleman, Texas, where he will devote his time to practicing in that territory. His office is located in the Coleman Petroleum Building.

LINCOLN F. ELKINS is now chief engineer of the Sohio Petroleum Co. in Oklahoma City. The former vice-chairman of the Petroleum Branch received his BS degree from the Colorado School of Mines and completed a year of graduate study at the University of Texas. He has been with Sohio for several years.

H. A. Davis has opened a new distributorship for International Harvester industrial engines in Dallas, to be known as the H. A. Davis Power Equipment Co. He has been for the past 10 years the district manager and application engineer for Twin Disc Clutch Co., having worked with Oil Well Supply Co. and Douglas Aircraft prior to that time. He is a 1936 mechanical engineering graduate of the University of Southern California.

E. L. (DICK) ANDERS, JR., is opening consulting offices in Abilene, Tex. Since 1953 he has been chief engineer of SACROC. Prior to that he was with the Creole Petroleum Corp. in Venezuela from 1946 to 1948, associate professor of petroleum engineering at the University of Kansas from 1948 to 1951, and chief reservoir engineer with International Petroleum Co., Ltd., in Peru from 1952 to 1953. He holds a BS degree from the University of Texas and a MS degree from Colorado School of Mines.



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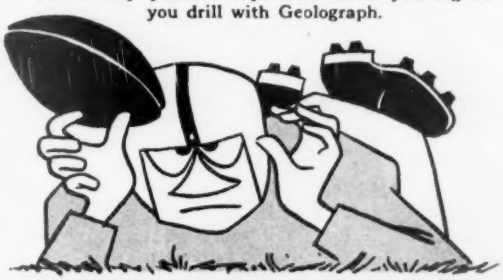

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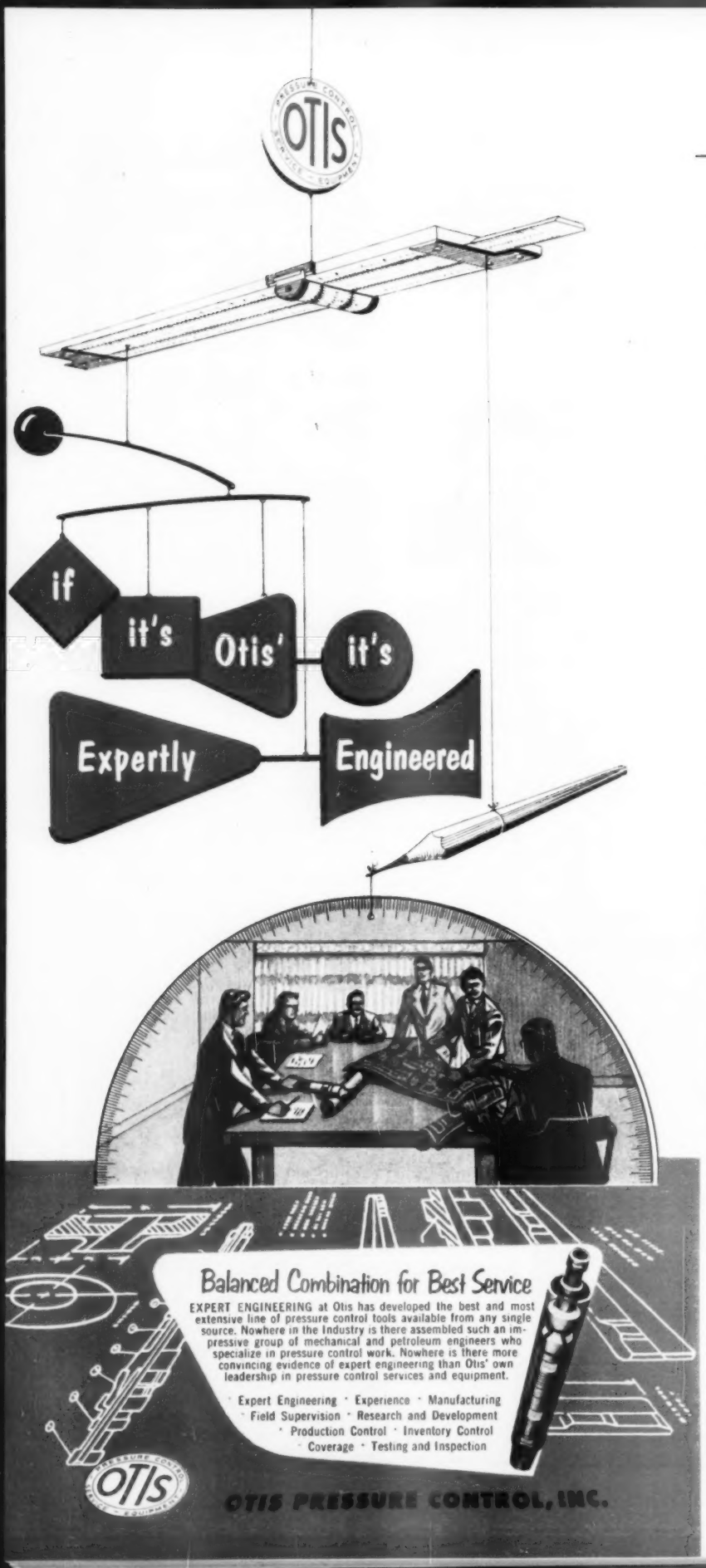
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(Continued from page 56)

E. J. DEWEES, petroleum engineer with the Bureau of Mines, Bartlesville, was a mining geology graduate of Pennsylvania State University in 1923. He has worked with the Bureau of Mines since 1924.

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IZAAK HAVENAAR has been a research technologist with Koninklijke/Shell Laboratorium at Amsterdam since 1951. The graduate of Technical University, Delft, Holland, is in charge of drilling fluids research.

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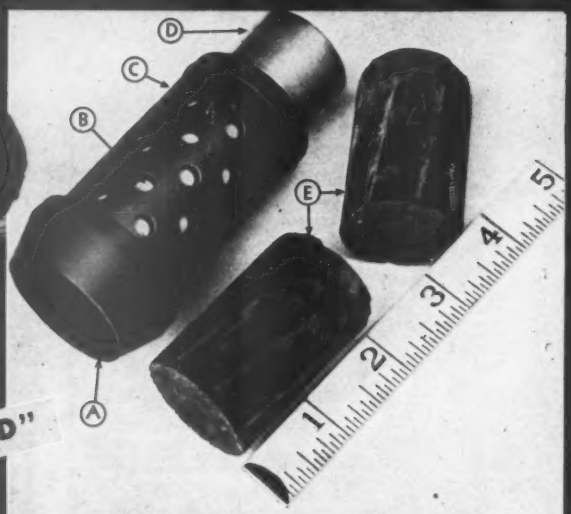

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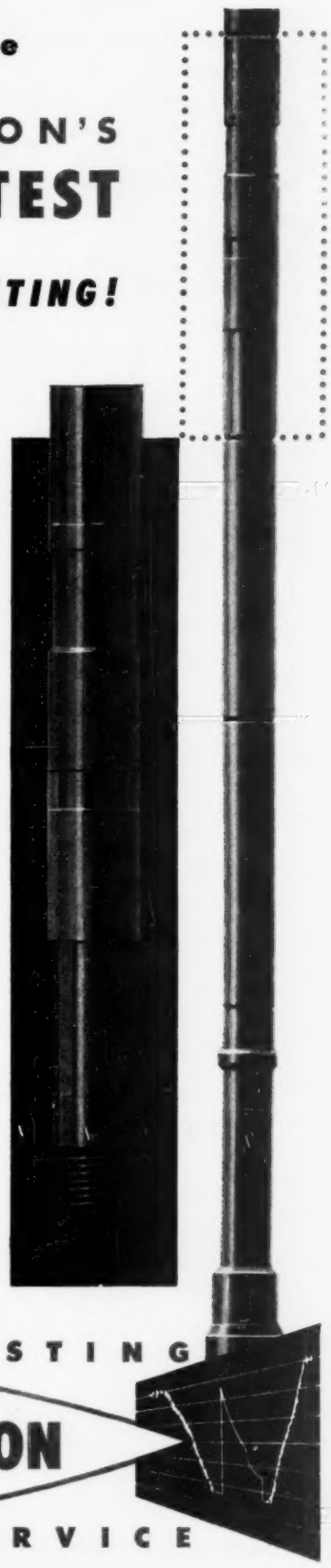

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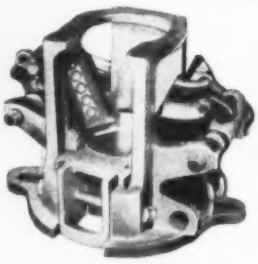

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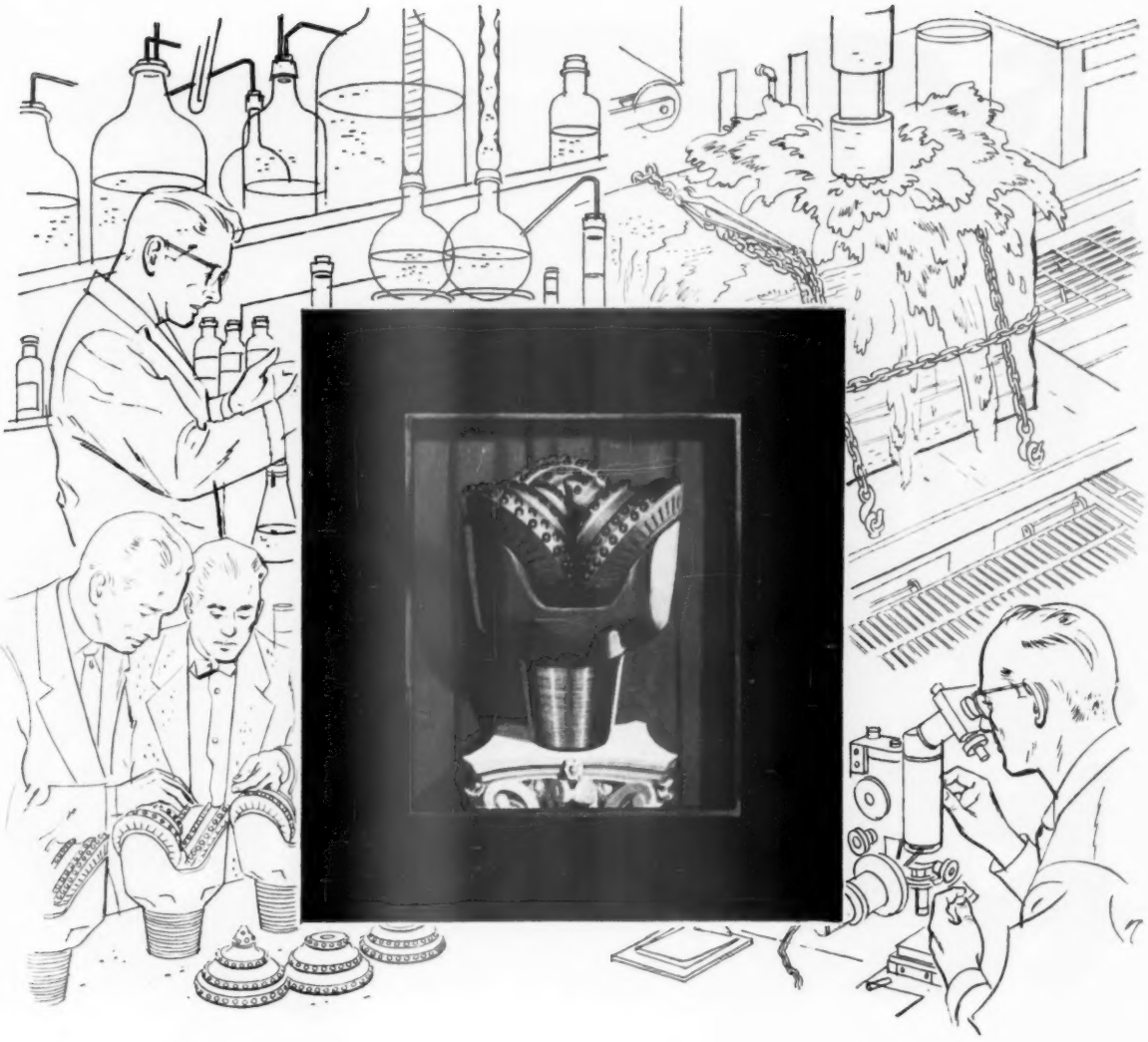

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